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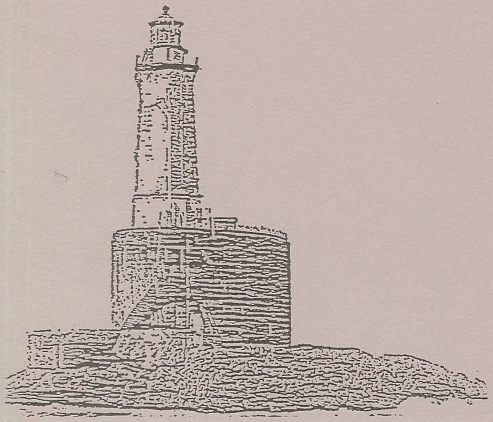
No. 53 Offshore Central And Northern California



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PREFACE

Air quality is a major environmental consideration in the potential development of oil and gas resources on the California OCS. In order to evaluate the potential impact of Lease Sale No. 53 on onshore air quality, BLM entered into a contract with Environmental Resources Group (ERG), Los Angeles California (Contract No. AA551-CT9-23). Form and Substance Inc. performed the air quality modeling under subcontract to ERG.

Kevin Golden, Air Quality Meteorologist, with the Pacific Outer Continental Shelf Office, Los Angeles, California, was the Bureau of Land Management Project Manager for this study. Dr. Stephen Kahane and Dr. Ralph Sklarew were project managers for ERG and FAS, respectively.

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PREFACE

This study was prepared for and in cooperation with the Bureau of Land Management. It is intended to serve as a support document to the Bureau of Land Management's assessment of air quality impacts in its Environmental Statement on Outer Continental Shelf (OCS) Lease Sale No. 53. An Executive Summary presenting the major findings of this study is available as a separate document.

Major subcontractual support for this study was provided by Form & Substance, Inc. (FAS). FAS assisted Environmental Resources Group (ERG) by compiling the ambient air quality and meteorology data (Chapter IV), and performing the air quality modeling and impact assessment (Chapter VI). The following lists, in alphabetical order, the names of the primary participants within each contributing company and their area of responsibility:

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The authors would like to express their appreciation to the many groups and individuals who helped in providing data and assuring the quality of the study. Following is a list of a few of the individuals and their affiliations. Many others, more than can be mentioned here, also provided assistance and input:

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I. INTRODUCTION

This study prepared by Environmental Resources Group and Form & Substance, Inc. assesses the anticipated air quality impacts of potential Outer Continental Shelf (OCS) oil and gas development activities off central and northern California. The study is specifically intended to support the air impact assessment in the U.S. Department of the Interior's Environmental Statement (ES) on OCS Lease Sale No. 53. The analysis is based on the oil and gas resource estimates for Sale No. 53 developed by the U.S. Geological Survey, and related transportation scenarios developed by the Bureau of Land Management (BLM).

The following chapters examine the air quality regulations and standards applicable to Lease Sale No. 53 activities, the air emissions likely to result from the various phases of the proposed development, their potential impacts on onshore receptor areas, and mitigating measures and strategies available to minimize perceived impacts. The assumptions and calculations presented are based upon the best available historical information and the future OCS expectations provided by BLM. However, given the uncertainties which surround many aspects of future OCS development, some simplifying assumptions were necessary. These assumptions were selected to provide conservative estimates of maximum impacts (that is, an upper bound on expected impacts).

In particular, the U.S. Department of the Interior (DOI) is currently developing regulations which would place limitations on air pollutant emissions generated by OCS operations. Because the regulations have not yet been finalized and the limitations which might be employed by the oil companies are only a matter of speculation at this time, emission estimates in this study are conservatively based on the best available engineering data on current OCS practice. No specific limitations other than those currently in force or expected to be in force in the near future are assumed.

Given these assumptions, and the fact that many of the emission factors/calculations presented are necessarily approximate, the data provided in this study should be taken to show relative magnitudes and distributions rather than exact representations of peak emissions and impacts. It is expected that, with implementation of the DOI regulations, air emissions and impacts of many of the OCS activities described in this report may be reduced.

A. Purpose and Objective of the Study

The purpose of this study is to assess the potential air quality impacts of OCS oil and gas development in central and northern California, in support of the U.S. Department of the Interior, Bureau of Land Management's Environmental Statement (ES) on OCS Lease Sale No. 53.

The specific objectives of the study are to:

1. Delineate, review and analyze the applicable federal, state and local air quality laws, regulations that would pertain to OCS Oil and Gas Sale No. 53 activities.

2. Summarize the available climatological, meteorological and air quality data for the study area.

3. Develop a comprehensive operation/emission inventory of potential Sale No. 53 activities.

4. Assess the potential air quality impacts of Sale No. 53 and related emissions through the use of air pollution diffusion modeling techniques.

5. Identify and assess potential mitigation measures which would or could be taken to minimize potentially adverse air quality impacts associated with OCS oil and gas development in central and northern California.

B. Geographic Area Encompassed by the Study

The study area and tract locations for Sale No. 53 are shown in Figure I-1. Five lease tract areas are assessed in this study. They are referred to as the Eel River, Point Arena, Bodega, Santa Cruz and Santa Maria zones.

The study area consists of the North Coast, San Francisco Bay Area, North Central Coast and South Central Coast Air Basins. The eastern boundaries of these basins comprise the inland extent of the area considered in assessing air quality impacts. (Refer to Figure III-3 for a map of the California Air Basins.) The study impact area is actually defined by geographic and meteorological factors. The air basin boundary concept is a compromise between actual physical limits to pollutant transport and politically defined limits. For this study, however, the air basin boundaries are recognized as being far enough inland so that any air impacts of Sale No. 53 beyond these boundaries would be negligible.

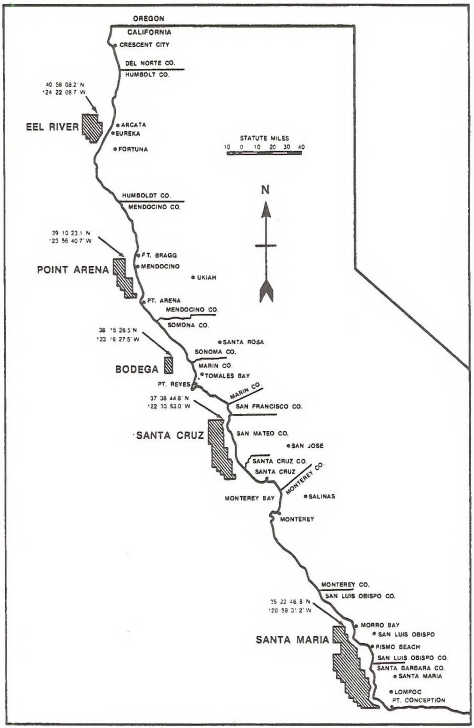

Figure I-1. OCS LEASE SALE NO. 53 STUDY AREA

II. PRODUCTION FORECASTS

A. Forecast Development

The U.S. Geological Survey (USGS) has the responsibility for conducting a geological and geophysical investigation of each potential lease sale tract in order to estimate the amounts of potentially recoverable oil and gas. For Lease Sale No. 53, the USGS (1978) prepared estimates of the amounts of potentially recoverable oil and gas resources in terms of the probability that at least the amount stated would be economically recoverable from a particular area. The probability levels used by the USGS were 95 percent (low quantity of recoverable oil and gas), 5 percent (high quantity of recoverable oil and gas), and the mean. This study focuses on the air quality impacts which could result if the mean resource recovery estimates are realized. The high and low resource recovery estimates are then discussed in terms of how much greater or smaller the impact on air quality could be.

The USGS used their resource estimates to project the numbers of wells, platforms, tankers or barges, the sizes and lengths of pipelines, oil and gas production rates, etc., likely to be associated with Sale No. 53. The variation in production rates and facilities combined with the probability of recovering a specific quantity of oil and gas was also addressed by the USGS. Because the conditional totals of the five zones could not be added to obtain a meaningful resource estimate for Lease Sale No. 53 in total, a risked mean estimate of economically recoverable oil and gas was prepared for each area. The USGS (1978) states:

> There is a certain risk factor associated with each area relative to the likelihood that hydrocarbons are present to the extent given by the conditional mean. The "risked mean" expresses this additional factor [see Table II-1].
>
> It is the position of USGS that the conditional mean for an area is not statistically independent. Therefore, do <u>not</u> make comparisons between areas (e.g., regarding platforms, wells, etc.) as all items are developed from the conditional mean for that particular area. The only comparisons that can be made between areas (or between an area and the whole Sale 53 area) are those involving the risked resource estimates noted above.

Throughout this study, all calculations are based upon the data provided by the USGS about the mean conditional resource recovery estimates. Supplemental information comparing activities and emissions for the 95 and 5 percent probability levels (as reported by the USGS) with the mean values are given in condensed discussions in subsequent sections.

B. Existing and Future OCS Activity

According to the USGS, exploration and delineation of the various tracts would occur between 1981 and 1985. The number of requisite wells would vary with the amount of oil and gas expected to be recovered and with the results of preceding test wells. Table II-2 presents the USGS mean resource recovery estimates for Lease Sale No. 53. Table II-3 shows the rate of exploratory drilling

and the total number of exploration and delineation wells which could be required in each zone for the mean resource recovery estimates.

According to the USGS projections, platform and pipeline construction would begin in 1985 and production would begin in 1986. As can be seen in Table II-3, production well drilling could continue for several years--through 1993 in the case of the Santa Maria zone. The maximum level of construction activity and of production activity do not generally occur in the same year. Also, each zone would reach its maximum production level in different years.

1. Eel River

The Eel River zone is expected to yield sweet gas, with possibly minor amounts of oil. By 1988, the USGS predicts 29 wells would be drilled and 18 would be producing gas. The rate of development for these first 7 years is shown in Table II-2. A platform would be installed in 1985 and a subsea or floating production system would be built in 1986 for two wells, according to the USGS information. USGS also estimates that 1987 and 1988 would be the peak production years. The subsequent expected decline in production can be seen readily in Table II-2, which lists the USGS annual production estimates of oil and gas within each zone from 1986 through 2005.

If the high resource recovery estimates are realized, the USGS estimates that 15 more wells would be drilled, with 6 more being producing wells. In conjunction with this possible increase in production, one deep water platform would need to be installed in 1987 and two more wells would need to be completed subsea. The USGS calculates that total production from 1986 through 2005 would nearly double to 350,500 million cubic feet (MMCF) of gas.

If the USGS low resource recovery estimates are correct, only 16 wells would be drilled and only 8 would be producing gas. All 8 wells would be planned as subsea completions connected to a single subsea or floating production system. During an estimated 20 years of production, only 62,800 MMCF of gas would be expected to be recovered.

2. Point Arena

Both oil and gas are expected to be recovered from the Point Arena area. The USGS anticipates 101 wells would be drilled and 87 wells would be producing by 1990, as shown in Table II-3. A deep-water platform and an OS&T would be installed in 1985 to process the gas and oil from those wells. Two subsea or floating production systems would be planned for installation to service 27 wells with subsea completions - one in 1987, the second in 1988. Peak production would be reached in 1989. The annual estimated oil and gas production from 1986 through 2005 is given in Table II-2. During this 20 year period 129,100 thousand barrels (MB) of oil and 134,200 MMCF of gas are expected to be recovered.

If the high resource estimates are recovered, the USGS projects 26 more wells would be drilled, with 21 of them producing. The USGS expects that only 12 of these wells would be connected to the two subsea floating production systems and that a second deep-water platform would be built. Total oil and gas production for the 20 years between 1986 and 2005 would be 204,100 MB of oil and 213,900 MMCF of gas.

Table II-1. U.S. GEOLOGICAL SURVEY ESTIMATES OF ECONOMICALLY RECOVERABLE RESOURCES

	Oil (million barrels)				Gas (billion cubic feet)			
	Conditional Probility				Conditional Probability			
Area	95%	5%	Mean	Risked Mean	95%	5%	Mean	Risked Mean
Eel River	--	--	--	--	63	356	182	71
Point Arena	87	205	131	25	86	215	134	25
Bodega	8	50	23	8	8	51	22	8
Santa Cruz	16	273	123	113	16	277	123	113
Santa Maria	89	784	404	402	89	795	409	404
TOTAL				548				621

Source: USGS, 1978.

Table II-2. U.S. GEOLOGICAL SURVEY ESTIMATE OF OCS LEASE SALE NO. 53 ANNUAL OIL AND GAS PRODUCTION - MEAN RESOURCE RECOVERY ESTIMATE

Zone:	Eel River		Point Arena		Bodega		Santa Cruz		Santa Maria	
	Oil (MB)[1]	Gas (MMCF)[2]	Oil (MB)[1]	Gas (MMCF)[2]	Oil (MB)[1]	Gas (MMCF)[2]	Oil (MB)[1]	Gas (MMCF)[2]	Oil (MB)[1]	Gas (MMCF)[2]
1986	10,300		3,400	3,500	1,200	1,100	600	600	3,100	3,200
1987	18,300		9,600	10,000	2,900	2,700	3,500	3,700	13,300	13,600
1988	18,300		14,800	15,400	2,500	2,400	7,300	7,700	25,400	26,000
1989	18,200		16,700	17,300	2,200	2,100	10,600	11,100	33,600	34,400
1990	18,200		14,100	14,600	2,000	1,900	12,300	13,000	39,900	40,900
1991	18,200		11,900	12,400	1,700	1,600	11,500	12,100	42,200	43,300
1992	15,000		10,000	10,400	1,500	1,400	10,100	10,700	38,000	38,900
1993	12,400		8,500	8,800	1,400	1,300	8,900	9,400	32,800	33,600
1994	10,100		7,200	7,500	1,200	1,100	7,900	8,300	28,300	29,000
1995	8,300		6,100	6,300	1,100	1,000	6,900	7,300	24,300	24,900
1996	6,800		5,100	5,300	900	900	6,100	6,500	21,100	21,600
1997	5,600		4,300	4,500	800	800	5,400	5,700	18,200	18,600
1998	4,600		3,600	3,700	700	700	4,800	5,000	15,700	16,100
1999	3,800		3,100	3,200	600	600	4,200	4,400	13,500	13,800
2000	3,100		2,600	2,700	600	600	3,700	3,900	11,700	12,000
2001	2,600		2,200	2,300	500	500	3,300	3,400	10,100	10,300
2002	2,100		1,900	2,000	400	400	2,900	3,000	8,700	8,900
2003	1,700		1,600	1,700	400	400	2,500	2,700	7,500	7,700
2004	1,400		1,300	1,400	300	300	2,200	2,400	6,300	6,400
2005	1,200		1,100	1,200	300	300	2,000	2,100	5,600	5,700
TOTAL	180,200		129,100	134,200	23,200	22,100	116,700	123,000	399,300	408,800

Source: USGS (1978).

1. MB = thousand barrels.
2. MMCF = million cubic feet.

Table II-3. RATE OF WELL DRILLING AND FACILITIES CONSTRUCTION NECESSARY FOR OIL AND GAS DEVELOPMENT IN OCS LEASE SALE NO. 53 (MEAN RESOURCE ESTIMATE)

Year	Stage of Development	Number of Wells Drilled (Subsea Completions)					Number of Platforms Installed				
		Eel River	Point Arena	Bodega	Santa Cruz	Santa Maria	Eel River	Point Arena	Bodega	Santa Cruz	Santa Maria
1981	Exploration and Delineation	1	1	2	4	4					
1982		5	5	3	12	12					
1983		4	6	1	15	17					
1984		1	2	0	10	11					
1985		0	0	0	4	5	1(1	1(2 1(4	1(1 1(4	1(1 1(4	2(1 1(4
1986	Production	6	14	10	8	21	1(3			1(1 1(3	2(1,1(2 1(5
1987		12(2)	28	16	26(5)	63		1(3		1(1	2(1 1(3
1988		0	28(14)	0	36(3)	82(4)		1(3		1(1	2(2
1989		0	17(13)	0	36	69(4)					1(1,1(2 1(3
1990		0	0	0	26	64(5)					
1991		0	0	0	5	46(5)					
1992		0	0	0	0	9					

Source: USGS, 1976.

1. In water depth ≤ 1,200 feet.
2. In water depth > 1,200 feet.
3. Subsea of floating production system.
4. OS&T.
5. Gas processing platform.

If the USGS low resource estimates are correct, only 67 wells would need to be drilled and only 58 would be producing wells. At this production level, the USGS suggests that one subsea or floating production system, serving 10 wells, would be sufficient. Maximum production would probably occur in 1987, and the total recovered oil and gas from 1986 through 2005 would not be expected to exceed 86,700 MB of oil and 86,300 MMCF of gas.

3. Bodega

The USGS expects that only oil will be recovered from the Bodega area. Whatever amount of gas would accompany the oil would be reinjected into the formation, according to the USGS document. The USGS predicts that by 1987, the year of peak production, 32 wells would be drilled and 26 would be producing oil (see Table II-3). The USGS further calls for a platform and an OS&T to be installed in 1985. The annual estimated production for the period 1986 through 2005 is given in Table II-2. The total oil recovered during this time would be 23,200 MB of oil and 22,100 MMCF of gas would have been reinjected.

If the USGS high resource estimates are realized, 25 more wells would be drilled. There would then be a total of 43 producing wells. In addition, a second platform would be installed in 1987. Total oil production estimated by the USGS for the period between 1986 and 2005 would be 50,000 MB with the peak production year occurring in 1988. 50,800 MMCF of gas would be extracted with the oil. The USGS has not indicated whether this gas would be utilized.

For the low resource estimates, the USGS predicts that only 21 wells would be drilled. Production from 16 wells over 20 years would amount to 8,100 MB of oil being recovered, with 8,100 MMCF of gas being reinjected.

4. Santa Cruz

The USGS expects that both oil and gas would be recovered from the Santa Cruz zone. Construction activities are expected to include installing a platform and an OS&T in 1985, a platform and a subsea or floating production system in 1986, a third platform in 1987 and a final one in 1988. As shown in Table II-3, by 1991, 183 wells are planned to be drilled with 137 wells producing oil and gas. Only 8 of these are expected to be subsea completions. The USGS projects that total production from 1986 through 2005 would be 116,700 MB of oil and 123,000 MMCF of gas. Peak production would be in 1990.

If the USGS high resource estimates are accurate, there would be a total of 301 wells drilled with 237 wells producing. Of these, 14 are planned for subsea completion. Three additional platforms and one more subsea or floating production system would be needed to process this increased oil and gas recovery. The total production for the 20 years between 1986 and 2005 is estimated by the USGS to be 271,300 MB of oil and 277,000 MMCF of gas.

If the low resource estimates are recovered, the USGS calculates 63 wells would be drilled and only 32 would be producing. USGS further estimates that only three platforms and an OS&T would be required. Production would peak in 1989 and 1990. The total resources recovered over 20 years would be 15,600 MB of oil and 15,600 MMCF of gas.

5. Santa Maria

The Santa Maria zone is forecast to yield both oil and gas. As can be seen in Table II-3, the USGS projects 403 wells would be drilled by 1993; 351 of these wells, including 18 completed subsea wells, would be producing. The USGS estimates that between 1985 and 1989, 7 conventional platforms, 4 deep-water platforms, a gas processing platform, an OS&T, and 2 subsea or floating production systems would be constructed. Total production from 1986 through 2005 is anticipated to be 399,300 MB of oil and 408,800 MMCF of gas. Annual production estimates for the USGS mean probability estimate are shown in Table II-2.

If the high resource estimates by the USGS were to prove accurate, 523 wells would be producing of the 598 planned to be drilled. Of the production wells, 31 would be subsea completions. Four additional conventional platforms, 2 added deep-water platforms, 1 more subsea or floating production system and another OS&T would also be required.

If the low resource estimates are realized, the USGS foresees only 166 wells being drilled, of which 137 would be producing wells. None would be subsea completions. Two conventional platforms, 4 deep-water platforms and an OS&T would also be expected. Production is forecast to reach maximum levels in 1990. Total production between 1986 and 2005 would be 85,500 MB of oil and 88,900 MMCF of oil.

C. References

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III. AIR QUALITY REGULATORY CONSIDERATIONS

A. Regulatory Authority Overview

1. Introduction

This chapter discusses the federal, state and local air pollution control statutes and regulations which pertain to outer continental shelf (OCS) oil and gas development and production. There are distinct sections dealing with the federal, state and local roles in regulation of OCS air emissions. In addition, the final section summarizes the implications of these diverse regulations for OCS Lease Sale No. 53.

A great deal of uncertainty and controversy surrounds the regulation of OCS air emissions. Recent litigation, the fact that the Department of the Interior (DOI) has not yet issued its final OCS air emissions control regulations, and the divergent opinions held by state and local regulatory authorities and the oil companies with regard to the regulation of OCS air emissions all contribute to the perceived lack of regulatory definition of OCS air emissions. Hence, the following sections also include, where appropriate, discussions of recent litigation and other factors giving rise to regulatory uncertainty.

2. Federal Authority

a. Environmental Protection Agency (EPA)

1. Policy Overview

Under the Clean Air Act as amended in August, 1977, EPA is responsible for the establishment of national ambient air quality standards (NAAQS) to protect the public health and welfare. Attainment and maintenance of the ambient standards rests primarily with each individual state. Methods for attainment and maintenance of the standards are to be outlined in State Implementation Plans (SIP) submitted for EPA approval by each state. The methods and strategy outlined in the SIPs must satisfy the requirements of Section 110 (a)(2) of the 1977 Clean Air Act. The plans must include: provisions for attainment of primary and secondary ambient air quality standards within specified deadlines; emission limitations and enforcement programs necessary to implement the plan; provisions for monitoring, compiling and analyzing of ambient air quality data; stationary source permit programs for major new or modified sources; adequate provisions prohibiting stationary sources from emitting air pollutants which would prevent maintenance or attainment of standards, and interfere with Prevention of Significant Deterioration (PSD), visibility measures and interstate pollution abatement; provisions for adequate personnel, funding and authority to carry out implementation plans; provisions (if necessary) for periodic inspection and testing of motor vehicles; provisions for plan revisions; requirements for stationary sources locating in nonattainment areas; provisions for consultation and public notification; and provisions for stationary source fees.

Pollutants not in attainment of the NAAQS are to reach compliance status as expeditiously as possible and in the case of national primary ambient air standards not later than December 31, 1982. If the primary ambient air quality standards for photochemical oxidants or carbon monoxide (or both)

cannot be met by the December 31, 1982 deadline despite implementation of all reasonably available measures, an extension to December 31, 1987 may be granted. States requesting an extension are required to establish a vehicle emission control inspection and maintenance program in addition to other SIP requirements. EPA can approve or disapprove state plans; and where state plans are deemed inadequate, EPA can promulgate its own requirements.

Primary national ambient air quality standards as set forth in the Clean Air Act amendments of 1970 were originally scheduled for attainment by May 31, 1975. Many of the nation's air quality control regions, however, were unable to meet this deadline. As a result, these regions were faced with a prohibition on new sources locating in their area. In order to allow some industrial growth, EPA adopted its National Emissions Offset Policy (also known as the Interpretative Ruling) in December, 1976. The Offset Policy allows for major new growth in nonattainment areas (i.e., in violation of the NAAQS) provided that air quality improves as a result of such growth. Improvement would occur through emission reductions from existing sources such that emissions from a proposed new source would be "offset" by a greater than one-to-one ratio. The National Offset Policy has since been incorporated into the 1977 Clean Air Act and has also been revised as of January, 1979.

While EPA's Emissions Offset Policy applies to nonattainment areas, PSD regulations apply to areas with air quality cleaner than the national standards (attainment areas). PSD regulations were first promulgated in 1974 in response to the court case Sierra Club vs. Ruckelshaus and then made statutory by incorporation into the 1977 Clean Air Act. PSD regulations are to be incorporated into the implementation plan for each state, and PSD authority is to pass to the state upon petition after EPA approval of the SIP. Following the Clean Air Act 1977 Amendments, EPA promulgated new PSD regulations and revision guidelines in June, 1978. Further changes have been proposed as of September 5, 1979 in response to the preliminary U.S. Court of Appeals (District of Columbia Circuit) decision on Alabama Power Company et al. vs. Costle, as discussed below.

ii. Ambient Air Quality Standards (AAQS)

Primary standards to protect human health and secondary standards designed to protect public welfare have been established for sulfur dioxide (SO_2), total suspended particulates (TSP), nitrogen dioxide (NO_2), carbon monoxide (CO), photochemical oxidants (measured as ozone), non-methane hydrocarbons and lead. These standards are presented in Table III-1.

Pursuant to the Clean Air Act as amended in 1977, the EPA administrator must promulgate a short term (no more than three hours) national primary ambient air quality standard for nitrogen dioxide concentrations. In addition, the EPA must review national ambient air quality standards every five years and determine whether revisions are needed. EPA is planning to assess the short and long term NO_2 standards simultaneously since the same scientific information is used to develop both standards. An interim criteria document for the short term NO_2 standard was completed in May 1978 and a review draft criteria document forming the basis for review of both NO_2 standards is scheduled for completion soon.

Table III-1. AMBIENT AIR QUALITY STANDARDS

Pollutant	Averaging Time	California Standards[1] Concentration[3,6]	National Standards[2] Primary[3,4]	Secondary[3,5]
Oxidant (Ozone)	One Hour	0.10 ppm (200 $\mu g/m^3$)	235 $\mu g/m^3$ (0.12 ppm)	Same as Primary
Carbon Monoxide	Twelve Hours	10 ppm (11 mg/m^3)		
	Eight Hours	-	10 mg/m^3 (9 ppm)	Same as Primary
	One Hour	40 ppm (46 mg/m^3)	40 mg/m^3 (35 ppm)	
Nitrogen Dioxide	Annual Average	-	100 $\mu g/m^3$ (0.05 ppm)	Same as Primary
	One Hour	0.25 ppm (470 $\mu g/m^3$)	-	-
Sulfur Dioxide	Annual Average	-	80 $\mu g/m^3$ (0.03 ppm)	-
	24 Hours	0.05 ppm[7] (131 $\mu g/m^3$)	365 $\mu g/m^3$ (0.14 ppm)	-
	Three Hours	-	-	1,300 $\mu g/m^3$
	One Hour	0.5 ppm (1,310 $\mu g/m^3$)	-	-
Suspended Particulate Matter	Annual Geometric Mean	60 $\mu g/m^3$	75 $\mu g/m^3$	60 $\mu g/m^3$
	24 Hours	100 $\mu g/m^3$	260 $\mu g/m^3$	150 $\mu g/m^3$

Table III-1 (continued)

Pollutant	Averaging Time	California Standards[1] Concentration[3,6]	National Standards[2] Primary[3,4]	Secondary[3,5]
Sulfates	24 Hours	25 $\mu g/m^3$	-	-
Lead	30-Day Average	1.5 $\mu g/m^3$	-	-
	3-Month Average	-	1.5 $\mu g/m^3$	-
Hydrogen Sulfide	One Hour	0.03 ppm (42 $\mu g/m^3$)	-	-
Hydrocarbons (corrected for methane)	Three Hours (6-9 a.m.)	-	160 $\mu g/m^3$ (0.24 ppm)	Same as Primary
Ethylene	Eight Hours	0.1 ppm	-	-
	One Hour	0.5 ppm		
Visibility-Reducing Particles	One Observation	Insufficient to reduce the prevailing visibility to less than ten miles when the relative humidity is less than 70%		

Notes:

1. California standards are values that are not to be equaled or exceeded.
2. National standards, other than those based on annual averages or annual geometric means, are not to be exceeded more than once per year.
3. Concentration is expressed first in units in which it was promulgated. Equivalent units given in parentheses are based upon a reference temperature of 25°C and a reference pressure of 760 mm of mercury. All measurements of air quality are to corrected to a reference temperature of 25°C and a reference pressure of HG (1013.2 millibars). In this table, ppm refers to ppm by volume, or micromoles of pollutant per mole of gas.

Table III-1 (continued)

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4. National Primary Standards: The levels of air quality necessary, with an adequate margin of safety, to protect public health. Each state must attain the primary standards no later than three years after the state's implementation plan is approved by the Environmental Protection Agency (EPA).
5. National Secondary Standards: The levels of air quality necessary to protect the public welfare from any known or anticipated adverse affects of a pollutant. Each state must attain the secondary standards within a "reasonable time" after their implementation plan is approved by the EPA.
6. Prevailing visibility is defined as the greatest visibility which attained or surpassed around at least half of the horizon circle, but not necessarily in continuous sectors.
7. This state standard is violated if there is also a simultaneous violation of the state one-hour oxidant standard or the state 24-hour suspended particulate matter standard.

The NAAQS serve as national baseline standards. Other than those based on annual averages or annual geometric means, the standards are not to be exceeded more than once per year. Each state must attain the primary standards no later than three years after its implementation plan is approved by EPA. The secondary standards must be attained by each state within a "reasonable" time after the SIP has been approved. EPA has set a July 1, 1979 deadline for SIP approval. States not meeting the deadline may be subject to federal highway funding cut-offs and a moratorium on new source approval.

The SIPs outline the means by which individual states will meet the national ambient air quality standards. Each state may adopt 1) any standard or limitation for emissions of air pollutants or, 2) any requirement for the control or abatement of air pollution provided that the emission standard or limitation is more stringent than those currently in effect under an applicable implementation plan or under Sections 111 or 112 of the 1977 Clean Air Act. California ambient air quality standards are presented in Table III-1.

iii. Regulations for Attainment Areas - PSD

Prevention of Significant Deterioration (PSD) regulations arose as a result of the Clean Air Act provision to "protect and enhance" the quality of the nation's air and the question as to whether "clean" air should be allowed to be degraded to the national standards. A series of suits culminating in Sierra Club vs. Ruckelshaus were successful in preventing EPA from approving state implementation plans which did not prevent significant deterioration of clean air. As a result, EPA promulgated PSD regulations for sulfur dioxide and total suspended particulates in December, 1974. These regulations prohibited construction of stationary sources in 19 specified categories unless Best Available Control Technology (BACT) would be applied for the two pollutants, and that emissions of those pollutants would not cause significant deterioration of clean air. An area classification system was devised to determine significance. Class I areas would allow only small incremental increases in sulfur dioxide and total suspended particulates. Class II areas would allow moderate increases; and in Class III areas, increases up to the ambient standard would be permissible. No incremental increase limitations were set for the other criteria pollutants.

PSD requirements were revised somewhat after passage of the 1977 Clean Air Act, becoming more comprehensive and restrictive. The PSD requirements as outlined in the Act dealt with allowable increments and ceilings for sulfur oxide and particulate matter, area redesignations, preconstruction requirements and a regulatory scheme for other pollutants. With respect to the latter requirement, the 1977 Clean Air Act directed EPA to promulgate PSD regulations for hydrocarbons, carbon monoxide, photochemical oxidants and nitrogen oxides by no later than August 7, 1979. As of December 1979, EPA had not issued those regulations.

In November 1977, EPA took the following four regulatory actions to carry out the new PSD requirements set forth by the 1977 Clean Air Act.

- EPA promulgated amendments regarding mandatory Class I areas, PSD increments, and new Class III reclassification procedures.

- EPA proposed regulations to provide guidance on SIP revision preparations.

- EPA proposed changes to the existing PSD regulations in light of new preconstruction requirements.

- EPA designated March 1, 1978 as the effective date for new preconstruction review and BACT requirements.

As a result of the above measures, a massive challenge by industry and environmentalists was mounted against EPA's PSD regulations (Alabama Power Company vs. Costle). This court case resulted in EPA's proposal of major PSD revisions on September 5, 1979. A per curiam text opinion was delivered to allow EPA to proceed as quickly as possible to commence rulemaking or other procedures necessary to promulgate PSD revision as necessitated by the court decision, and to take whatever actions needed to effectuate congressional policies. The court intended to review EPA's attempt to conform to its summary opinion before issuing its final opinion. The court order is stayed until all petitions for rehearing have been completed. Until the final opinions are delivered, EPA will not know if the order is retroactive, thus invalidating existing permits.

Following the U.S. Court of Appeals mandate, EPA proposed changes and revisions both to the PSD regulations and also to rules affecting nonattainment new source review. The full text appears in the Federal Register, September 5, 1979 (44 FR 51924). Some of the more significant differences between the existing and proposed regulations are dicussed below:

- Definition of major emitting source. Under existing PSD regulations, major emitting sources are those that emit or have the potential to emit (uncontrolled emissions) 100 tons or 250 tons/year (depending on the source category) of any regulated pollutant. The emission limitation applies on a pollutant specific basis, i.e., just to those pollutants above the cut-off level. The new proposed regulations would calculate potential emissions after the application of air pollution controls and apply on a source specific basis, i.e., one pollutant over the applicable limit would render all pollutants subject to PSD review.

- Fugitive emissions. Fugitive emissions are presently included in the calculation of total potential emissions from sources. The new proposed regulations would require both a separate rule to regulate fugitive emissions and a determination of the specific plant types from which fugitive emissions could be accurately measured.

- Geographic applicability. The present PSD regulations apply to those sources constructed in nonattainment areas that would have an adverse impact on clean air areas. The proposed regulations differ in that sources constructed in nonattainment areas would not be subject to PSD regulations unless their emissions were to affect a clean air area in another state. EPA is petitioning the court to reverse its rule or to allow regulation of sources affecting Class I areas or Indian reservations.

- De minimis levels. Existing PSD regulations exempt sources from PSD review if controlled emissions are less than 50 tons/year, 1,000 lbs/day or 100 lbs/hour, whichever is more stringent. The proposed

PSD regulations would require "de minimis" significance levels to be used as guidelines. Pollutants below the "de minimis" levels would be exempt from PSD review. Significance levels for criteria pollutants would be 10 tons/year except for CO which would be 100 tons/year.

- Modifications of existing sources. Existing PSD regulations define major modified stationary sources as those modified sources with emission increases of 100 or 250 tons/year, depending on the source category. These regulations apply on a pollutant specific basis and do not allow offsetting emission reductions achieved within the source. The new proposed PSD regulations would exempt major modifications from PSD permit review if the pollutant emissions were below significance levels described above. The calculation of emissions would allow for other emission reductions within the source.

- Best Available Control Technology (BACT). Existing PSD regulations require BACT for each attainment pollutant increase greater than 50 tons/year controlled emissions. Emissions reductions within the source may be used to exempt the BACT requirement given a zero net increase in emissions for the particular pollutant and that the modification is not a new or reconstructed piece of equipment. Under the proposed PSD regulations, BACT would be required for all pollutants regulated under the Act for which there is a significant (de minimis) increase. This requirement would apply to new or reconstructed equipment as well.

iv. Regulations for Nonattainment Areas - Emissions Offset Policy

Nonattainment areas are those areas that are not currently in compliance with the NAAQS. EPA's Emissions Offset Policy, adopted in 1976, sets forth preconstruction review regulations designed to limit and reduce emissions from new and modified stationary sources in nonattainment areas. Unlike the PSD provisions, air quality provisions for nonattainment areas are intended not only to prevent excessive increases in emissions but also to actually reduce emissions.

With the passage of the 1977 Clean Air Act, EPA's Offset Policy remained in effect, except that the baseline for determining emission offset credit was changed and the source applicability expanded. In January 1979, EPA revised the Offset Policy to reflect public comments on the original ruling and the changes required by the 1977 Clean Air Act. The revised Offset Policy is to remain in effect during development, submittal and approval of the required State Implementation Plans (SIPs).

EPA's 1979 Offset Ruling reflects the 1977 Clean Air Act's revised definition of a major source; that is, one that directly emits or has the potential to emit 100 tons/year of any pollutant. EPA has defined the phrase "potential to emit" as the maximum capacity to emit a pollutant in the absence of air pollution controls. Since this definition of a major source increased the coverage of the 1979 Offset Policy, EPA introduced a two-tiered review process. Under this procedure, a new or modified major source is largely exempt from the Offset Policy if its allowable (i.e. controlled) emissions, after meeting any New Source Performance Standard (NSPS) or SIP emission

limit, are less than the following cut-off points: 50 tons/year, 1,000 lbs/day or 100 lbs/hour. Exempted sources must still comply with other applicable SIP requirements. Accompanying emissions offsets within a source are not acceptable in determining emission cut-off levels.

Volatile organic compounds (VOC) as precursors of photochemical oxidants (measured as ozone) are subject to the Emission Offset Policy but because of the technical uncertainties of oxidant formation and transport, these VOC sources are subject to a slightly different criterion. In addition to Offset Policy compliance required for major VOC sources locating within areas that are designated or shown to be nonattainment for oxidants, those sources located within 36 hour pollutant travel time of a known oxidant nonattainment area are also subject to the ruling. Wind conditions associated with high oxidant concentrations are to be employed for calculation of pollutant travel time and exemption will be granted if it can be shown that the proposed VOC emissions will not affect an oxidant nonattainment area (intended for rural areas).

In summary, all major new sources, including those located in PSD areas, must be reviewed to determine if they will cause or contribute to a NAAQS violation. For proposed major new sources or modifications that would significantly contribute to a NAAQS violation, the following conditions must be met prior to source approval:

- Lowest Achievable Emission Rate (LAER). LAER limitations will be imposed on those pollutants which will be emitted in excess of the allowable emission threshold limits. LAER must be at least as stringent as EPA's New Source Performance Standards and does not take into account the cost of the control technology.

- Existing Sources Controlled. The applicant must show that all major sources owned, operated or controlled in the same state are in compliance with the state SIP or applicable attainment schedule.

- Emission Offsets. Intrapollutant emission offsets (reductions) must be obtained from existing sources in the area such that there will be reasonable progress toward attainment of the applicable NAAQS.

- Net Air Quality Benefits. Emission offsets must provide a net air quality benefit in the affected area so that there will be reasonable further progress toward attainment of the applicable NAAQS. Emissions of the "stable" pollutants (sulfur dioxide, particulate matter and carbon monoxide) in excess of the allowable emission thresholds will be subject to this requirement.

Since areawide oxidant and nitrogen dioxide levels are not directly dependent on specific hydrocarbon or nitrogen oxide (NO_x) source locations, EPA has decided that for VOC and NO_x, satisfying the previous emissions offset condition will be considered adequate with respect to the net air quality benefit stipulation. Finally, the January 1979 revised Offset Policy allows the reviewing authorities to exempt temporary emission sources from the major Offset Policy requirements.

Further revisions to the nonattainment Emission Offset Policy were proposed by EPA on September 5, 1979, concurrent with proposed PSD revisions.

Although the court decision (Alabama Power Company vs. Costle) leading to the required PSD revisions did not specifically address nonattainment provisions, EPA has stated that the statutory definitions (especially "major source" and "modification") and concepts addressed by the court with respect to PSD regulations are relevant also to nonattainment areas.

The following major revisions to the Emission Offset Policy have been proposed:

- Definition of major emitting source. The proposed offset policy would redefine "potential to emit" to include the use of air pollution control equipment. Emissions would still be subject to the ruling on a pollutant specific basis.

- Modification of existing source. Under the existing policy, cut-off limits for source exemption are similar to those mandated for new sources. Emissions offset reductions within the source are not included in the calculation of emissions. Proposed revisions would allow in-source emission reductions, given a complete and EPA-approved SIP.

- De minimis levels. As stated earlier, a source emitting less than 50 tons/year, 1,000 lbs/day or 100 lbs/hour, whichever is more stringent, of controlled emissions is currently exempt from Offset Policy requirements. Under the proposed revisions, the same de minimis levels as proposed for PSD regulations would replace the above threshold limits.

- Lowest achievable emission rate (LAER). The proposed revisions would increase the LAER exemption level of controlled emissions from 50 tons/year to 100 tons/year for new sources. LAER would be required for each piece of equipment added to an existing source regardless of offsets obtained.

- Geographical applicability. The proposed Emission Offset Policy revisions are similar to the existing policy except that clean sub-areas of nonattainment areas are not recognized. Sources located in nonattainment areas would be subject to LAER and offset requirements regardless of whether it could be shown that the source would not significantly affect the actual nonattainment area.

The court decision (Alabama Power Co. vs. Costle) has resulted in much uncertainty concerning the existing EPA regulations for PSD and nonattainment areas, especially in the context of the state implementation plans. EPA proposes for now to approve any SIP revision if it satisfies either the existing EPA regulations or those proposed as of September 5, 1979. The former approach is legally acceptable since the court decision was stayed and Sec. 405(d) of the Clean Air Act as amended in 1977 provides that states must have time to comply with altered EPA regulations. It is anticipated that final regulations adopted by EPA in response to the court's decision will not go into effect until early 1980. In the meantime, the fate of the SIP is unclear. A particular concern is that sources may be subject to both federal and state PSD reviews with the potential for inconsistent or conflicting requirements.

v) Offset Policy and PSD Overlap

Although the Emissions Offset Policy and PSD regulations are aimed at sources locating in two different classification areas, there may be some instances where new sources would be reviewed under both sets of requirements. Under the 1977 PSD regulations, sources locating in a nonattainment area would be subject to PSD if the source would have an adverse impact on attainment areas. Also, since both PSD and nonattainment requirements are currently applied on the basis of individual pollutants, a source may locate in an area that is nonattainment for one pollutant and attainment for another. The source would then have to comply with both sets of requirements. Sources that would be subject to both PSD and nonattainment review requirements may have to deal with both federal and state agencies since nonattainment review is currently administered by the state and PSD is generally administered by EPA.

Under EPA's proposed PSD revisions, sources locating in nonattainment areas would not be subject to PSD regulations for major pollutants unless their emissions would affect an attainment area in another state. Also, the revised PSD requirements would be applicable on a source specific basis; that is, once one attainment pollutant is emitted in excess of the specified cutoff limits, PSD would apply to all other pollutants emitted by the source in significant amounts. Under these circumstances, nonattainment pollutants emitted in minor amounts (less than 100 or 250 tons/year depending on source category) would be exempt from LAER and offsets as required under the Offset Policy ruling but would still have to apply BACT to prevent new violations or worsening of existing violations. Nonattainment pollutant emissions exceeding 100 or 250 tons/year would be subject to the nonattainment requirements.

b. Department of the Interior

The Department of the Interior (DOI) is the agency responsible for the regulation of OCS air quality. This authority is provided by Section 5(a)(8) of the Outer Continental Shelf Lands Act Amendments of 1978, which requires DOI to provide regulations "for compliance with the national ambient air quality standards pursuant to the Clean Air Act (42 USC 7401 et seq.), to the extent that activities authorized under this Act significantly affect the air quality of any State."

In spite of this mandate, the exclusivity of DOI's regulatory authority has been clouded by two occurrences. On April 18, 1978, EPA published a notice in the Federal Register (43 FR 16393), in which it concluded that portions of California's SIP for the maintenance of certain air quality standards should be applied to a platform located in federal OCS waters. EPA further stated that in the absence of EPA-approved New Source Review (NSR) and PSD provisions in California's SIP, NSR and PSD provisions promulgated by EPA would apply. This action by EPA raised a serious jurisdictional question: did EPA, DOI or both have responsibility for the control of air pollutant emissions arising from OCS activities in federal waters? Resolution of this issue occurred on August 20, 1979 when the U.S. Court of Appeals for the Ninth Circuit ruled that DOI, and not EPA, has the authority to regulate air quality over the OCS.

The second occurrence which challenged DOI's exclusive authority to regulate OCS air emissions occurred in 1978 when the State of California and the Santa Barbara Air Pollution Control District filed a suit against Exxon Corp., Exxon Pipeline Company of California, Chevron U.S.A. Inc., Shell Oil Company, and Cecil Andrus (Secretary of the Interior) (California v. Exxon Corp. 78-2849 RMT, C.D. Cal. 1978). The action was a complaint for injunctive and declaratory relief and for civil penalties regarding a violation of air quality standards. In essence, California endeavored to require the installation of air pollution control equipment on a platform sited beyond the three-mile limit (i.e., in federal waters). In his Order (for dismissal) United States District Court judge for the Central District of California stated:

> The matter being duly submitted and it appearing to the Court that Plaintiffs' claims rest entirely on the theory that the State of California has jurisdiction for the purpose of controlling air pollution to regulate activities connected with the production, processing and transportation of petroleum from the Santa Ynez Unit, which is outside the three-mile limit, (i.e., outside the borders of California,) and it further appearing to the Court that the State has no such jurisdiction, and it further appearing to the Court that the authority granted to the Secretary of the Interior by the OCS Lands Act with respect to petroleum operations on the Outer Continental Shelf excludes any authority by the State over such operations... the motion for a preliminary injunction is denied....

In order to develop the OCS air pollution control regulations required of it by the Outer Continental Shelf Lands Act amendments of 1978, DOI published a notice in the Federal Register on December 28, 1978. This notice requested comments to assist DOI to identify and develop a regulatory program for OCS air pollution control. On May 10, 1979 DOI published proposed OCS air pollution regulations (44 FR 27448). Some of the significant and controversial features of these regulations are discussed below; comments of oil companies and state and local agencies regarding DOI's proposed regulations, where appropriate for perspective, are also included.

i. Emissions Cutoff Levels

DOI proposes that uncontrolled (i.e., in the absence of air pollution control equipment) sources emitting air pollutants at a rate equal to or less than 100 tons/year would be exempt from further regulatory review. Controlled emissions of less than 50 tons/year would also be exempt. These threshold levels were adopted from EPA's new source review regulations for onshore nonattainment areas. Sources exceeding these levels must employ air pollution modeling to determine whether their emissions cause "significant" impacts (see Section III.A.2.b.ii below). Exempt sources may also be required to perform modeling to determine whether the expected emissions meet the "significantly affect" test if a state submits information to the DOI which demonstrates that the emissions would significantly affect the air quality of an area in the state.

The State of California in its comments (Greene, 1979) on DOI's proposed regulations suggested this approach would not provide sufficient air quality protection. The state maintained that:

... the Clean Air Act and state and local regulations in California base the determination of pollution control and mitigation requirements on the amount of emissions coming from a source rather than on the concentration those emissions have when they reach the ground ... One significant difference between the Clean Air Act and the proposed regulations is that while excessive emissions trigger control and mitigation requirements under the Clean Air Act, the same emissions level triggers only further studies under the proposed regulations.

Western Oil and Gas Association (WOGA) views the emissions cutoff levels differently. Gary McClintock expressed WOGA's opinion at the public hearing held by DOI on June 7, 1979 in Los Angeles:

> First, the exemption threshold allowed for offshore emissions sources should, as your staff agrees, be higher than for sources located on the shore. Because a plume rapidly spreads and dilutes as it leaves an emissions source, a facility located on the OCS will have a lesser impact on onshore air quality than a source of otherwise equivalent emission characteristics located at the shoreline. The further offshore the OCS source is located, the higher the exemption limit should be.

WOGA's position is echoed by Bruce Beyaert, who spoke on behalf on the American Petroleum Institute at the public hearing held on the proposed DOI regulations in Washington D.C. on June 14, 1979:

> The proposed regulations would ensnare proposed OCS activities which would have uncontrolled emissions over 100 tons per year and controlled emissions over 50 tons per year - regardless of how far offshore they would be. This represents an unjustified extreme in regulatory overkill.

ii. Significance Levels

As a means of evaluating the magnitude of the onshore impact produced by OCS development, DOI proposes to use the significance levels employed by EPA under its PSD and Emissions Offsets programs. These significance levels represent the maximum incremental increase in ambient onshore air pollution concentrations allowed as a result of OCS activities. The levels are approximately two percent of the national AAQS for all pollutants except hydrocarbons. For volatile organic compounds (VOC) DOI will use the concept of pollutant travel time to shore, i.e., VOC emissions will be considered significant if they can travel to shore in less than 36 hours under meteorological conditions associated with the presence of elevated ozone levels onshore.

California generally finds this definition of significance unacceptable (Greene, 1979):

> ...This approach is fallacious and inadequate in several respects. First, it uses the concentration of pollutants resulting from a single project as an indicator of the

impact of that project, while the actual impact of air pollution on human health is the result of that project in combination with literally millions of individual sources of air pollution. The notion that an individual project or source must have a significant or measureable impact on ambient air quality concentrations before its pollution would be subject to controls is absurd in areas such as the coastal regions of Southern California.

API also found reason to disagree with DOI's proposed significance levels. Testifying on behalf of API at the hearings in Washington, Bruce Beyaert offered the following as one of seven specific recommendations:

> If the applicant's emissions would exceed the site-specific emission threshlds, the [DOI] should allow the applicant to show through modeling that reasonable significance levels would not be exceeded. API continues to believe that a shoreline air quality impact should be considered significant only if it exceeds ten percent of a national ambient air quality standard. The significance levels proposed in Section 250.57-1(c)(2)(i) are excessively stringent.

iii. Control of Air Pollutants Other Than VOC

DOI's proposed regulations require:

> Any activity whose emissions exceed the significance levels [as demonstrated by modeling]... shall be deemed to significantly affect the air quality of the state for that pollutant and shall be subject to the following:
>
> (i) In nonattainment areas, the lessee shall take whatever measures are necessary to fully reduce or offset the emissions so that there is no impact from these emissions in the onshore ambient air...
>
> (ii) In attainment areas or in areas which are unclassifiable on the basis of existing information, the lessee shall apply the best available control technology to ... reduce emissions which significantly affect the onshore ambient air. The lessee shall model emissions from the source after the application of the best available control technology to determine whether the ambient concentration of emissions exceeds the ... maximum allowable increases... If the maximum allowable increases are exceeded the lessee shall apply whatever additional controls are necessary to reduce or offset emissions so that concentrations ... do not exceed the maximum allowable increases. [The maximum allowable increases are those permitted by EPA in its PSD program.]

In short, lessees whose activities result in onshore concentrations greater than the significance levels are required to reduce emissions through

controls and/or offsets so there is "no effect" onshore in nonattainment areas. In attainment areas, lessees are required to employ BACT plus additional controls or offsets as needed so that onshore concentrations do not exceed the maximum allowable increases, which are those developed by EPA as part of its PSD program.

iv. Control of VOC Emissions

DOI's proposed regulations include provisions for VOC sources which have uncontrolled emissions greater than 100 tons per year or controlled emissions greater than 50 tons per year:

> (i) When [VOC] emissions are within 36 hours travel time of a nonattainment area, the lessee shall take whatever measures are necessary to reduce or offset all emissions through the installation of emission reduction control technology or by obtaining offsets equivalent in nature and quantity of the emissions which must be reduced...
>
> (ii) When [VOC] emissions are within 36 hours travel time of an attainment or unclassifiable area subject to meteorological conditions that are associated with nonattainment conditions in the vicinity, the lessee shall apply the best available control technology.

Briefly stated, the proposed regulations require that VOC emissions which could significantly offset a nonattainment area be fully controlled and/or offset. Sources of VOC emissions impacting an attainment area must employ BACT.

v. Control of Temporary Activities

Temporary activities which have significant onshore impacts (demonstrated by modeling) are required to employ BACT. DOI defines temporary activities as "operations associated with the construction of platforms on the OCS, or activities related to exploration for or development of OCS oil and gas resources which are conducted in one location for less than three years" (44 FR 27456).

vi. Role of State and Local Governments and Standards

The proposed DOI regulations do not explicitly provide state and local authorities with permit-approval responsibilities. However, some respondants to DOI's May 10, 1979 announcement suggested that DOI require the OCS lessee to obtain a local air quality permit as a prerequisite to approval of its plan for development and exploration (44 FR 27451). In making its decision, DOI stated that it believed (44 FR 27451):

> ...that state and local governments will play an adequate quate and important role in the decision-making process relating to activities authorized under the Act. Besides the authority to review and comment upon exploration plans and development and production plans, a state with an approved coastal zone management program has the opportunity to consider onshore air impacts as part of its consistency review of OCS plans. Also, the Department expects a

willingness on the part of lessees to consult with state and local government officials during the plan development stage.

California has expressed its concern (Greene, 1979) that this approach may not "acknowledge the critical air quality conditions in coastal southern California (and inland of these areas)," and that this would result in "economic dislocations." California suggests that "this result can be easily avoided by a review process which is locally based rather than centrally determined" (Greene, 1979).

DOI's proposed regulations do not include explicit provisions for compliance with state AAQS. California's comments on the proposed DOI regulations addressed this issue (Greene, 1979):

> As recognized by Congress, federal standards are a floor representing minimal protection only. In cases like California where meteorology, dense populations and major industry combine to create unique witches brews of pollution, and extreme violations of federal standards, tighter-than-federal standards are necessary in some cases to provide any assurance of protecting public health. Consequently, these standards should be protected from violation by offshore activities as are federal standards and as the OCS Lands Act Amendments require.

Mr. McClintock, in further testimony at the public hearings on the proposed regulations held in Los Angeles (June 7, 1979), indicated WOGA's concerns regarding state air quality standards and the role of state and local governments in OCS-related air pollution regulation:

> ...we [WOGA] concur with your conclusion that state air quality standards and other local air pollution regulations cannot be applied to the OCS, at least under these regulations. There are several reasons for this. First and foremost, the governing statute authorizes the Secretary to promulgate regulations only for compliance with national ambient air quality standards. State air quality standards obviously are not national in nature...

The sections above have discussed some of the major provisions of DOI's proposed OCS air pollution control regulations, and presented some of the divergent opinions and positions that DOI will consider in its preparation of the final regulations, which are expected to be issued in early 1980. In addition to the regulatory controversies discussed above, it should be noted that there are several other regulations on which divergent opinions are held, including the definition of "source," cumulative impacts, the stringency of control required for BACT or for offsets, where and when BACT should be required, enforcement techniques and authority, etc.

c. U.S. Coast Guard

Under the OCS Lands Act (Sec. 21 (b,c)), the U.S. Coast Guard is authorized to promote the safety of life and property on fixed OCS platforms and drilling vessels. In addition, the Coast Guard is responsible for safety

and operating guidelines and regulations for tankers in U.S. waters. The Coast Guard supervises specific personnel licensing procedures, minimum manning levels for ships and boats, the regulation of safety equipment on all varieties of offshore facilities, and enforces oil pollution laws in both federal and state offshore waters. In some congested waters, the Coast Guard has instituted procedures establishing separate traffic lanes for vessels going in opposite directions; this voluntary Vessel Traffic Separation Scheme (VTSS) has been established in the Santa Barbara Channel and the Gulf of Catalina. The Coast Guard also has responsibility with EPA for spill prevention efforts and coordinates the National Oil and Hazardous Substance Pollution Contingency Plan.

Specific regulations pertaining to vapor recovery systems to be used during all crude oil transfer operations between ship and storage facilities are being developed by the Coast Guard. Demonstration projects conducted by the Jet Propulsion Laboratory of the California Institute of Technology and EPA are currently underway on the safety of proposed vapor recovery systems. Proposed regulations focusing on design standards will most likely be completed in 1981 with final regulations expected in 1982.

Any offshore storage and treatment facilities (or offshore loading and storage facilities) would fall under Coast Guard purview as a vessel and as an oil transfer facility. As such, the regulations outlined above would apply.

3. State Authority

Under California law, the state Air Resources Board (CARB) and local air pollution control districts share responsibility for air pollution control in the State. In addition, other state agencies may on occasion have some authority by virtue of the California Environmental Quality Act (CEQA). The following sections discuss the role of the CARB and local districts in air pollution control, and briefly present some relevant provisions of CEQA.

a. The California Air Resources Board

Statutory authority for the control of air pollution in California rests with both state and local authorities. The California Health and Safety Code provides: "Local and regional authorities have the primary responsibility for control of air pollution from all sources other than vehicular sources (§ 39002)." The code also states:

> The State Air Resources Board is the state agency charged with coordinating [local and regional] efforts to attain and maintain ambient air quality standards, to conduct research into the causes of and solutions to air pollution, and to systematically attack the serious problems caused by motor vehicles, which is the major source of air pollution in many areas of the state (§ 39003).

The CARB is also responsible for the preparation of California's State Implementation Plan (SIP) as required by the Clean Air Act, "... and, to this end, shall coordinate the activities of all districts [local and regional authorities] necessary to comply with that act (Health and Safety Code §39602)."

Both the CARB and local districts have developed a number of strategies to comply with the mandates of federal and state laws. Section III.A.4 describes some of the activities and regulations of the districts. This section discusses primarily the CARB's role in the promulgation of state AAQS preparation of the SIP, New Source Review (NSR), Prevention of Significant Deterioration (PSD), emissions offsets and nonattainment areas, and the Air Conservation Program.

i. Ambient Air Quality Standards (AAQS)

The CARB is required to "...adopt standards of ambient air quality for each air basin in consideration of the public health, safety and welfare.... (Health and Safety Code § 39606(b))." These standards, which may vary among various air basins, are based upon the recommendations of the State Department of Health. The CARB has promulgated state AAQS and they are presented in Table III-1, along with the federal AAQS developed by EPA. The state's AAQS are to be achieved and maintained through basinwide air pollution control plans developed by local authorities in each of California's air basins. However, the thrust of California's air pollution control efforts has focused on developing an SIP and meeting the mandates of federal law. Therefore, the development of air pollution control plans to meet state AAQS has not been completed, although some progress has been made, particularly in areas where federal and state air pollution control planning requirements overlap.

ii. State Implementation Plan

California's SIP is complex and voluminous. The CARB has organized the plan into 26 chapters. Some of these are informational and others conform to administrative requirements established by EPA. The plan for attainment and maintenance of the federal AAQS is contained in 14 chapters, one for each of California's designated air basins. Some of the larger air basin chapters contain several distinct coordinated plans, developed by local air pollution control districts.

Nine of the 14 chapters (or plans) mentioned above were subject to major revisions as part of California's 1979 SIP submittal to EPA; the remaining five did not require modifications to meet current federal requirements. Three of the nine chapters modified were plans for air basins adjacent to lease tracts proposed in Lease Sale No. 53 (i.e., the San Francisco, North Central Coast, and South Central Coast Air Basins).

California does not presently have an approved SIP. However, the EPA has indicated that California's SIP is generally approvable, except that an acceptable motor vehicle inpsection and maintenance plan, as required by federal law, is lacking (Rubenstein, 1979). This requirement should be met soon since the California legislature has indicated its intent to authorize a motor vehicle inspection and maintenance program during 1980, and implement it during 1981 (Senate Concurrent Resolution, Nov. 16, 1979).

Each of the 14 air basin plans of the SIP includes provisions for emissions limitations and reductions from existing sources and review of new sources designed to attain and maintain federal AAQS. Federal law also requires that the SIP address prevention of significant deterioration (PSD) and meet special requirements in nonattainment areas. These two elements and new source review are discussed separately in the following sections.

iii. New Source Review - The Model Rule

In 1977, the California legislature passed two resolutions directing the CARB to evaluate New Source Review (NSR) Rules of the air pollution control districts. Assembly Concurrent Resolution 19 directed the CARB to review best available control technology and emissions offset provisions of the districts' NSR rules. Senate Concurrent Resolution 17 further directed the CARB to review the SIP and possibly revise it to allow for community-wide trade-offs when considering permits for new sources. Pursuant to this mandate, the CARB adopted on February 16, 1979, after extensive public hearings and reviews, a Model New Source Review Rule and submitted it to the districts for their consideration. [California Health and Safety Code § 41503 grants the CARB authority to adopt rules (after a public hearing) for any district (except Bay Area) if it finds after a public hearing the district's rules "will not likely achieve" the ambient air quality standards.] The general provisions of the Model Rule are outlined below.

a) Applicability

The Model Rule requires that all stationary sources owned and/or operated by an applicant within the state be in compliance, or on an approved schedule for compliance with all applicable provisions of the SIP. The rule applies to all new sources (or modifications of existing sources) which would emit more than 250 pounds during any day of any pollutant for which there is a national AAQS (except carbon monoxide) or any precursor of such pollutants. In the case of carbon monoxide, the rule is applicable if the proposed source would cause the violation of a national AAQS at the point of maximum ground level impact. In addition, some specific sources are exempt from the provisions of the rule, e.g., essential public services, certain fuel conversions, cogeneration projects, and facilities using innovative control technologies.

b) Stationary Source - Definition

The Model Rule includes a comprehensive definition of the term stationary source:

> Stationary Source includes any structure, building, facility, equipment, installation or operation (or aggregation thereof) which is located on one or more bordering properties within the District and which is owned, operated, or under shared entitlement to use by the same person. Items of air-contaminant-emitting equipment shall be considered aggregated into the same stationary source...
>
> Emissions from all such aggregated items of air-contaminant-emitting equipment and all such associated items of non-air-contaminant-emitting equipment of a stationary source shall be considered emissions of the same stationary source. The emissions from all cargo carriers (excluding motor vehicles) while operating within the Air Basin, including marine vessels while operating within the California Coastal Waters adjacent to the Air Basin, which load or unload at the source shall be considered as emissions from the stationary source.

The definition of "California Coastal Waters" is based upon meteorologial data compiled and analyzed by the CARB. According to the CARB's analysis, pollutants emitted over these waters are likely to be ducted under or within the inversion layer to the coast under predominant summer airflows. At some points along the California coast, the coastal waters extend as far as 70 miles seaward.

c) Emissions Profiles

The maximum design capacities of a new source are used to determine its emissions profile unless the applicant agrees to specified limitations on the operations of the proposed source. Based on these assumptions, an annual emissions profile is developed by plotting daily emissions in descending order (see Figure III-1). (Quarterly emissions profiles may be used to determine emissions from seasonal sources.) The emissions profiles are used to determine the mitigation requirements for the proposed source. (In some cases these profiles eliminate the need for air quality modeling during the permit review process.) The role of emissions profiles in determining mitigation requirements is discussed below.

d) Mitigation

All new sources (or modifications) subject to the rule are required to employ best available control technology (BACT). BACT is defined as the more stringent of: (1) the most effective emissions control achieved in practice; or (2) a control technology found by the CARB or the local district, after public hearings, to be technologically feasible and cost-effective; or (3) the most effective technology which EPA certifies is contained in any state's SIP.

Mitigation is required for each pollutant (or precursor) for which a national AAQS was exceeded within the air basin more than three discrete times (or, for annual standards, more than one time) during the three years prior to filing of the application for a permit. However, mitigation is not required for sulfur oxides, particulates or carbon monoxide if the applicant demonstrates through modeling that the new source will not cause a new violation or exacerbate an existing violation of an AAQS.

If mitigation is required, it is to be obtained through emissions offsets on a 1.2:1 offset ratio from sources (1) upwind of the proposed source, or (2) within a 15 mile radius of the proposed source. For offsets outside of these areas, the applicant must develop through modeling an offset ratio sufficient to demonstrate a net air quality benefit. In the event modeling is not used, an offset profile similar to the emissions profile is constructed and compared with the source's emissions profile to determine whether the source's emissions are offset at each point (by a 1.2:1 ratio) on the emissions profile (see Figure III-2). Alternatively, the applicant can average his emissions on a monthly basis and obtain an offset ratio of 2.0:1.

If the new source is to be located in an area not presently experiencing violations of any national AAQS, the stringent mitigation (offset) measures described above are not required. However, the applicant must demonstrate through modeling that the new source, including the effect of emissions offsets required as a permit condition would not cause a new violation of a national AAQS.

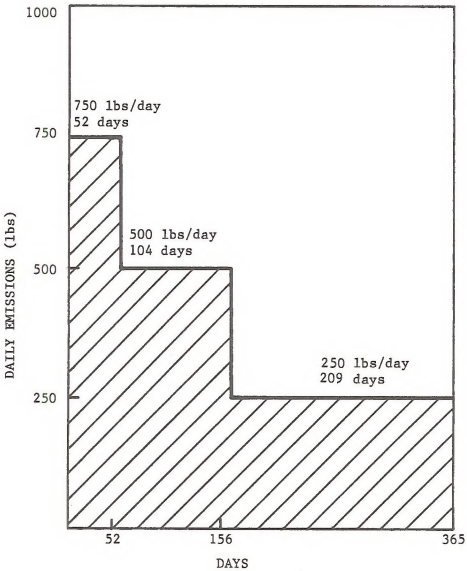

Figure III-1. SAMPLE ANNUAL EMISSIONS PROFILE

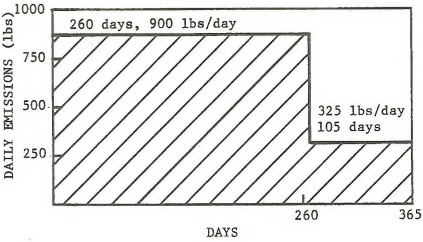

Figure III-2a. SAMPLE EMISSIONS OFFSET PROFILE

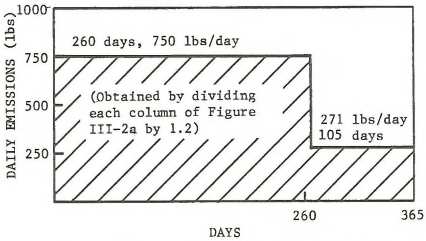

Figure III-2b. SAMPLE ADJUSTED EMISSIONS OFFSET PROFILE

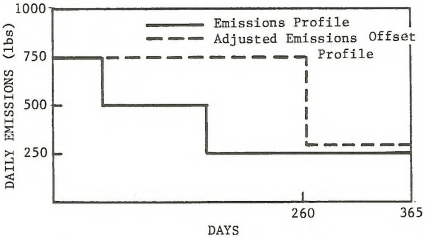

Figure III-2c. COMPARISON OF SAMPLE EMISSIONS PROFILE AND ADJUSTED EMISSIONS OFFSET PROFILE

If the applicant obtains emissions offsets on a 1.2:1 (or greater) basis for each pollutant, and precursors of such pollutants, for which there is a national AAQS, the proposed source is exempt from the PSD requirements of the EPA.

iv. Air Conservation Program

The CARB Air Consevation Program (ACP) was undertaken in 1976 in response to the federal mandate for a program for PSD in areas which already had air cleaner than the national AAQS. The CARB intended, in 1976, to classify all land areas in the state according to incremental increases in air pollution which would be permitted. Local and regional authorities were to be given a large role in the classification of these areas into one of four categories.

However, with the passage of the Clean Air Act Amendments of 1977, PSD became an EPA-administered statutory program. The PSD program is transferred to the states only when they have an approved SIP which includes a program to prevent significant deterioration of ambient air quality. The ACP is being revamped to reflect not only these amendments, but also the pending final opinion in the case of Alabama Power Co. vs. Costle.

The CARB staff tentatively plans to develop a revised ACP and hold public hearings and workshops on it during 1980, but no firm program requirements or deadlines have been established (Honcoop, 1979). In the absence of an ACP, the EPA's PSD regulations will continue to apply, except for new sources which are exempted via CARB's Model New Source Review Rule.

b. California Environmental Quality Act (CEQA)

California's legislature has expressed its concern for the protection of the environment through CEQA. This act requires the preparation of an Environmental Impact Report (EIR) prior to the commencement of projects which might adversely affect the environment. Thus, each individual, specific development project planned within the Lease Sale No. 53 area could be expected to need an EIR prepared which details its unique requirements and impacts. A relevant state agency is designated as the lead agency which oversees the preparation of the EIR and decides whether to grant final approval for a proposed project.

OCS-related projects which require state approval could be required to implement specified air pollution control strategies even if an air pollution permit, as such, is not required. For example, the lead agency (e.g. Coastal Commission, State Lands Commission) could require such equipment as a condition for approval. However, it is unlikely potential lead agencies, which generally have working agreements with the CARB, would impose requirements which are more stringent or differ greatly from CARB's requirements.

4. Local Authority

Figure III-3 provides a map of California Air Basins, including those of concern in the study.

a. North Coast Air Basin

i. Air Quality Maintenance Plan

The 1977 revised North Coast Air Basin Air Pollution Control Plan presents a general overview of air pollution control achievements and outlines requirements for further controls. The North Coast Air Basin is in attainment for all pollutants regulated by federal standards with the exception of particulates, which are emitted largely from lumbering and agricultural operations. The air basin is also in violation of the state standard for hydrogen sulfide. Present and future control efforts are directed at reducing particulate emissions and also excessive hydrogen sulfide emissions from geothermal development.

ii. Rules and Regulations

In 1976, all counties in the North Coast Air Basin adopted a uniform single set of control regulations (Regulation 1), with some stricter regulations in effect in Mendocino County due to increased residential and commercial activity. Federal New Source Performance Standards (NSPS) and National Emissions Standards for Hazardous Air Pollutants (NESHAP) have been adopted by all basin counties (Rules 490 and 492, respectively) and delegation has been received from EPA.

NSR procedures outlined in Rule 220 were adopted in 1976 and are being implemented while awaiting official EPA approval. The Basin Control Council is now reviewing proposed procedures for the prevention of significant deterioration of air quality in the Basin through the California Air Resources Board's Air Conservation Plan program. In addition to NSR standards, the only specific petroleum related rule outlined in Regulation 1 applies to control requirements for petroleum storage tanks in excess of 40,000 gallon capacity as specified under Rule 482. NSPS require that storage vessels for petroleum liquid be equipped with a floating roof, a vapor recovery system or an equivalent control, depending on the true vapor pressure of the liquid.

b. San Francisco Bay Area Air Basin

i. Air Quality Maintenance/Nonattainment Plan

The San Francisco Bay Area is currently a nonattainment area with respect to Federal standards for photochemical oxidants, carbon monoxide and TSP. With respect to the latter pollutant, Alameda County is designated nonattainment for the primary standard and four other counties are designated nonattainment for the secondary standard. However, EPA has recently proposed to redesignate Alameda County as attainment for TSP (Environmntal Reporter, October 5, 1979). The California one-hour standard for nitrogen dioxide is violated several times a year, particularly in the South Bay Area. The state's 24-hour sulfur dioxide standard was violated once in 1975 and may be violated in the future.

The 1979 Bay Area Air Quality Plan addresses the oxidant, carbon monoxide and TSP problems in the region. Of particular concern is the control of hydrocarbon emissions leading to the formation of oxidants (primarily ozone).

Figure III-3. CALIFORNIA AIR BASINS

Stationary source controls include the use of available control technology (ACT) for new and existing industries and a review and permit program (NSR) for new and modified air pollution sources.

ii. Rules and Regulations

The Bay Area Air Quality Management District has enacted 22 regulations to control air pollution. The following are relevant to a general discussion of OCS-related activities:

- Regulation Two (Division 13) outlines permit and NSR requirements for construction and operation of new and modified stationary sources. It includes consideration of future emission reductions (trade-offs) and requires the use of Best Available Control Technology.

- Regulation Three (Chapter One of Division Three) states specific requirements for petroleum storage tanks with a capacity greater than 150,000 liters (39,630 gallons). Chapter Three of Division Three requires that valves, flanges, relief valves, pumps and compressor seals, blind changing, crude oil production operations and loading of organic liquids or marine vessels conform to modern maintenance and operating practices used by superior operators of like equipment.

- Regulation Seven defines NSPS for new or modified sources of air pollution following EPA guidelines. Rule Nine requires that new or modified petroleum liquid storage vessels of more than 40,000 gallons capacity be equipped with a floating roof, a vapor recovery system, or their equivalents. This rule does not apply to storage vessels for petroleum or condensate stored, processed, and/or treated at a drilling and production facility prior to custody transfer.

- Regulation Ten limits emissions of organic compounds from leaking valves at petroleum refinery complexes to less than 10,000 ppm concentration (expressed as methane) above background.

- Regulation Thirteen lists requirements for the control of organic compound emissions from terminals and bulk plants. Emissions of greater than 0.65 pounds per 1,000 gallons of organic liquid loaded at a terminal are prohibited. Also, a vapor recovery system of at least 95% efficiency, or an equivalent vapor loss control system must be properly installed on storage tanks having a capacity of 2,000-40,000 gallons and must be properly connected during delivery of any organic liquid.

- Regulation Eighteen discusses the control of organic compounds from a petroleum refinery complex and sets standards for vacuum producing systems, wastewater (oil/water) separators and process vessel depressurization.

c. North Central Coast Air Basin

i. Monterey Bay Region (Monterey and Santa Cruz Counties)

a) Air Quality Plan

The North Central Coast Air Basin, consisting of Monterey, Santa Cruz and

San Benito Counties, is considered a rural area with respect to oxidant non-attainment area planning (Abercrombie, 1979). Given the rural designation, the minimum requirement for the Monterey Bay Region nonattainment plan would be adoption, in regulatory form, of Reasonably Available Control Technology (RACT) for stationary sources that have the potential to emit more than 100 tons/year of volatile organic compounds. In addition, a policy level commitment to target percentage reductions of hydrocarbon emissions from the transportation, stationary and area-wide source sectors to demonstrate attainment of the national standards would be required (Davis, 1978).

Monterey and Santa Cruz County are currently designated as nonattainment areas for ozone. The Air Quality Plan for the Monterey Bay Region as adopted in December, 1978, describes strategies recommended for improving regional air quality, consistent with the attainment of AAQS. The recommended strategies include measures relating to stationary sources, mobile sources, transportation and land use.

The following recommended measures for the control of stationary sources to be implemented by the Monterey Bay Unified Air Pollution Control District (MBUAPCD) are relevant to OCS petroleum-related activities/facilities:

- New Source Review (adopted July, 1976), Rule 208b, requires the Air Pollution Control Officer to deny permits for construction to any source if after construction or modification it emits more than 25 pounds per hour or 250 pounds per day of any pollutant (except carbon monoxide), which will cause a violation or interfere with the attainment or maintenance of any state or national AAQS.

- Petroleum Liquid Storage Fixed-Roof and Floating Roof Tanks (adopted May, 1978 as Rule 417). This strategy, aimed at reducing hydrocarbon emissions by 95 percent, requires the use of internal or external floating roofs or equally effective controls.

- Fugitive Emissions for Oil Production Facilities (not adopted as of November 27, 1979). Emissions from leaks around valves, flanges, compressor seals and other oil production equipment are to be reduced by proper maintenance practices.

Measures relating to the loading and unloading of gas and crude oil from ships and barges are to be considered in the future.

b) Rules and Regulations

The following Rules adopted by the Monterey Bay Unified Air Pollution Control District are relevant to OCS-related activities or facilities:

- Rule 207 discusses in detail the review of new or modified sources with respect to applications for Authority to Construct. Under Rule 207, "the emissions from all marine cargo carriers while operating within the Air Basin, including those marine cargo vessels operating within the California Coastal Waters adjacent to the Air Basin, which load or unload at the source shall be considered as emissions from the stationary source."

- Rule 208 sets standards for granting permits to operate. Prior to issuance of any Permit to Operate for a new or modified source, the source and any offset source must be operated consistent with their respective construction permits under Rule 207.

- Rule 417 sets forth detailed requirements for the storage of organic liquids (true vapor pressure greater than 1.5 psi) in tanks, reservoirs or containers of more than 150,000 liters (39,630 gallons) capacity. The use of internal or external floating roofs or other equally effective control is stipulated.

- Rule 423 lists general provisions for operations falling under the EPA category for New Source Performance Standards. Section G discusses requirements for storage vessels containing petroleum liquids (described previously under North Coast Air Basin rules and regulations).

ii. San Benito County

a) Nonattainment Plan

San Benito County is designated a nonattainment area for photochemical oxidant. Since it is a rural county without the capacity for generating sufficient hydrocarbon emissions to cause a violation of any ambient air quality standard, its nonattainment plan need only address control strategies for stationary sources which have the potential to emit more than 100 tons per year of hydrocarbons. No such stationary sources exist within the San Benito County boundary. The nonattainment plan does address, however, the question of pollutant transport into the county.

b) Rules and Regulations

Rules and Regulations for stationary sources of air pollution in San Benito County are implemented by MBUAPCD. (The joint air pollution control district was formed by the merging of air pollution districts for Santa Cruz, Monterey and San Benito Counties in 1974.) The regulations outlined in the previous section are therefore applicable in San Benito County. The county, however, lies about 25 miles inland, and is not expected to have any OCS-related stationary sources within its boundary.

d. South Central Coast Air Basin

i. San Luis Obispo County

a) Air Quality Maintenance Plan

All portions of San Luis Obispo County were initially designated nonattainment for photochemical oxidant; however, as a result of the February 1979 EPA change in the standard from 0.08 ppm to 0.12 ppm, all areas of the County now attain the standard and the CARB has formally petitioned EPA to change the status to attainment for ozone. The Salinas River Valley portion of the North County is, however, designated nonattainment for TSP with respect to the state standard. San Luis Obispo County is considered Class II for those pollutants that are not in violation of the national AAQS. San Luis Obispo County's original Air Quality Attainment and Maintenance Plan (now modified to an Air Quality Maintenance Plan) listed new and revised Reasonably Available Control Measures

(RACM) as identified jointly by EPA and CARB for hydrocarbon emissions from stationary sources. RACMs include the application of Reasonably Available Control Technology (RACT) to a category of existing sources through a rule or regulation. RACT is defined as "the lowest emission limit that a particular source is capable of meeting by the application of control technology that is reasonable available considering technological and economic feasibility." Although not currently required, the following measures relating to hydrocarbon emissions from potential OCS activities or facilities might be implemented in the future if the ozone standard were to be violated in the county:

- Control of hydrocarbon emissions from valves and flanges at refineries. Control measures would consist of properly maintained valve packings and flange connections.

- Seals on floating roofs at oil production fields, refineries, terminals and other facilities. A tight fit for existing primary seals would be required as well as installation of secondary seals on tanks storing petroleum product with a vapor pressure of more than 1.5 psia.

- Control of hydrocarbon emissions from ballasting of tankers. Emissions would be controlled by use of segregated ballast tanks or vapor recovery on transfer equipment.

- Control of hydrocarbon emissions from pumps and compressors at refineries. The control measure would consist of an effective preventive and corrective maintenance program.

- Control of hydrocarbon emissions from loading of marine tankers. Emission reductions would be accomplished by use of vapor recovery systems.

- Control of hydrocarbon emissions from oil-water separators. Control measures would consist of covering the exposed liquid surface with a fixed or floating roof.

- Control of hydrocarbon emissions from fixed roof tanks at refineries, terminals, and other facilities. Vapor recovery or internal floating roof controls would be installed.

b) Rules and Regulations

Rule 204 describes San Luis Obispo County's NSR policy for granting an Authority to Construct and Permit to Operate. The rule requires that all new stationary sources must comply with applicable district Rules, Regulations and Orders, SIP requirements, NSPS and NESHAP of the 1977 Clean Air Act. Under Rule 204, the definition of "stationary source" includes liquid cargo vessels unloading or loading at marine terminals. Emissions from such vessels would include those from engine operations, purging or venting of vapors and loading, storage, processing and transfer of organic liquid cargo.

Rule 407 sets forth organic material emission standards, limitations and prohibitions. Section A describes required control measures for storage tanks (capacity greater than 40,000 gallons) containing any gasoline or petroleum distillate. Regulations VI and VII are reserved for NSPS and Emission Standards for Hazardous Air Pollutants.

ii. Santa Barbara County

a) Air Quality Attainment Plan

Santa Barbara County is designated nonattainment for photochemical oxidants, carbon monoxide and total suspended particulates. The county is in attainment of the federal standards for the remaining EPA criteria pollutants (nitrogen dioxide, sulfur dioxide, lead). In order to meet federal ambient air quality standards in the future, the Santa Barbara Air Quality Attainment Plan recommends adoption of specific stationary source, mobile source and land-use control strategies. Under oxidant control strategy, the plan recommends implementation of the following: 1) motor vehicle inspection program, 2) RACM, 3) petroleum transport via pipeline, and 4) single tanker loadings.

The RACM referred to above apply to categories of volatile organic compounds (VOC) which are considered to be major sources of oxidant pollution. The RACM relevant to OCS oil and gas development for EPA Categories I and II were adopted by Santa Barbara County in compliance with Federal and State guidelines. EPA Category 1 refers to legally enforceable control measures required as part of the 1979 SIP revision submittals for nonattainment areas. Category II refers to measures that Santa Barbara County, as a nonattainment area, must commit to adopt beginning in January, 1980.

The CARB has also identified control measures judged to be reasonably available for inclusion in nonattainment plans for California areas. The following three categories have been established with respect to the time frame for adoption: Category 1 - measures which are reasonably available for inclusion in the plans in regulatory form; Category II - measures which are reasonably available, but are not expected to be ready for adoption in regulatory form in time for local plan submission to the CARB; and Category III - measures which ARB has not yet determined to be reasonably available in California.

In addition to the above, the Santa Barbara County Air Quality Attainment Plan specifically addresses the county's concern over OCS operations with respect to meeting the national AAQS for ozone in 1987.

b) Rules and Regulations

The following Santa Barbara County Air Pollution Control District rules and regulations may be applicable to projected OCS activities or facilities:

- Rule 205. New Source Review (revised July 2, 1979). The revised NSR Rule sets specific allowable emissions increases for new or modified sources (e.g. 5 pounds per hour) as well as requiring increasingly stringent BACT for sources exceeding the cut-off levels. The rule also discusses emission trade-offs including location of the trade-off source and the offset ratio required.

- Rule 310. Odorous Organic Sulfides. Rule 310 requires that ambient levels of hydrogen sulfide not exceed 0.06 ppm for a 3-minute averaging period or 0.03 ppm for a 1-hour averaging period (state standard).

- Rule 325. Storage of Petroleum and Petroleum Products (Revised June 11, 1979). Rule 325 rquires the use of a floating roof, a fixed roof

equipped with an internal-floating-type cover or a vapor recovery system for the storage of petroleum distillate or crude oil in containers of more than 40,000 gallon capacity. The rule sets specific requirements for floating roofs.

- Rule 326. Effluent Oil/Water Separators. Either a solid cover with all openings sealed, a floating pontoon or double-deck type cover equipped with closure seals, a vapor recovery system or equipment of equivalent efficiency is required for effluent oil/water separators.

- Rule 327. Organic Liquid Cargo Vessel Loading. After July 1, 1985, BACT will be required for the loading of organic liquid cargo into any organic liquid cargo vessel from any marine terminal.

- Rule 331. Refinery Valves and Flanges (adopted June 11, 1979). Hydrocarbon emissions limits from valves and flanges are set at 10,000 parts per million, expressed as methane, above background.

- Rule 332. Petroleum Refinery Vacuum Producing Systems, Wastewater Separators and Process Turnarounds (adopted June 11, 1979). Rule 332 sets specific control equipment and venting requirements, for vacuum producing systems, wastewater separators and process turnarounds.

- Rule 903. General Provisions New Source Performance Standards. The New Source Performance Standards include standards of performance for storage vessels for petroleum liquids (described under previous rules and regulation sections).

B. Implications of Air Quality Regulations for OCS Activities

This chapter has dealt with the federal, state and local air pollution control regulations which are, or have the potential to be, applicable to OCS oil and gas development and production. In this section, the major air pollution control requirements which OCS lessees must meet are summarized for both offshore and onshore facilities. The presentation explicitly indicates the regulatory uncertainties which arise as the result of proposed PSD and Offset Policy revisions, litigation, and the fact that DOI has not yet issued final air emission control regulations.

1. Offshore Requirements

The major set of air emission regulations with which OCS lessees will be required to comply are those promulgated by the DOI. In fact, these regulations may be the only applicable regulations in federal waters depending upon whether certain provisions of California's NSR are deemed by the courts to be applicable on the OCS (i.e., the provisions pertaining to air emissions in California Coastal Waters).

a. The DOI Regulations

DOI's proposed air emission regulations would require OCS lessees to determine through modeling whether their air emissions would result in onshore pollutant concentrations above specified significance levels. If these levels were exceeded in nonattainment areas the lessee would be required to fully

reduce or offset its emissions so there is "no impact" onshore. If the significance levels were exceeded in an attainment area the lessee would be required to employ BACT, and additional controls or offsets as needed so that the ambient onshore concentrations of emissions do not exceed specified maximum allowable increases.

Temporary activities (i.e., those with a duration of less than three years at any single location) would be required to employ BACT if modeling revealed their ambient onshore emission concentrations would exceed the specified significance levels.

The proposed DOI regulations do not grant permit-approval authority to state and local agencies, although these entities may comment upon any OCS development and exploration plans. In addition, they may also review such plans under the consistency review provisions of the Coastal Zone Management Act of 1972 (§307).

b. State Regulations

The CARB's Model NSR Rule would require any OCS-related onshore facility to include emissions from associated platforms and tankers. The emissions would be assumed to be emitted by the onshore facility and full mitigation (offsets) would be required. Hence, OCS platforms and tankers may be required to employ additional emission control technologies and/or emissions offsets in order to obtain approval for a related onshore facility. These provisions of the Model Rule have not yet been tested in the courts, so the question of their applicability to the OCS remains moot. However, if they are deemed applicable by the courts, they will require OCS lessees to employ more stringent controls and offsets than would be required by DOI's proposed regulations.

2. Onshore Requirements

Any proposed OCS Lease Sale No. 53 onshore facility will be subject to either PSD or Emission Offset requirements depending on the level of expected emissions of each pollutant and the area where the source will be located. Current PSD preconstruction review requirements will apply to any sources seeking to locate in a PSD area that have the potential to emit 100 tons per year or more of any regulated pollutant (if the source is one of 28 listed categories). If the source is not included in one of the listed categories, the cutoff level is 250 tons per year. The Emission Offset Policy will apply to any source potentially emitting more than 100 tons per year in either a nonattainment area, or a source located in a clean area, but which could affect a nearby nonattainment area. For both the PSD and the Emission Offset Policy, potential to emit does not include the use of air pollution control equipment, but EPA has proposed to change this definition to include the effects of control equipment.

Current PSD regulations require BACT for each attainment pollutant greater than 50 tons per year. In addition, an air quality analysis is required for each attainment pollutant greater than 50 tons per year and, for SO_2 and TSP, the modeled increment must not exceed allowable incremental increases. It is assumed that EPA's recently proposed PSD (and Emissions Offset Policy) revisions will remain essentially unchanged since they must comply with the dictates of the Alabama Power vs. Costle court decision. Promulgation of final PSD revisions similar to those proposed would reduce the number of sources subject to PSD

since the 100 or 250 ton/year cut-off level could take into account air pollution control equipment. However, since the proposed regulations are source specific, if one pollutant exceeds the cutoff level it would subject all the pollutants emitted from the source to PSD review.

The essential requirements of the existing Emissions Offset Policy for major new sources or modifications that would significantly contribute to a NAAQS violation are: Lowest Achievable Emission Rate (LAER), existing applicant-owned sources must be in compliance with all applicable regulations, emissions offsets, and a net air quality benefit. If the proposed Offset Policy revisions resulting from the Alabama Power Company vs. Costle court decision are implemented, cut-off limits for review of new sources would change from 100 tons/year uncontrolled emissions to 100 tons/year controlled emissions, thereby allowing more sources to avoid NSR. The application of stringent "de minimis" levels which EPA has established as a guideline could prove a greater hardship in the nonattainment areas since the LAER requirement for nonattainment areas does not take into account the cost of pollution control equipment.

In general, EPA's proposed revisions to both PSD and the Offset Policy raise a lot of uncertainty with respect to California's SIP. However, the SIP should be fully complete and responsive to EPA's proposed revisions by the time OCS Lease Sale No. 53 development begins.

Local APCDs have the authority to regulate onshore OCS-related facilities constructed within their boundaries. Gas processing plants and storage tanks are potential onshore facilities under BLM Transportation Scenario 1A. Most of the local districts that are adjacent to offshore OCS activities have defined stationary source to include in-port tanker loading/offloading operations. All districts have a rule requiring the use of floating roofs or equivalent level of control for onshore storage tanks for petroleum liquids. The construction of an onshore gas processing plant would fall under each APCD's NSR Rule.

There is some question as to whether a local agency could extend its jurisdiction to platforms and operations taking place in federal waters. For example, Monterey Bay Unified Air Pollution Control District's Rule 207 states that "[emissions from] marine cargo vessels operating within the California Coastal Waters adjacent to the Air Basin, which load or unload at the source shall be considered as emissions from the stationary source." Local APCDs with in-port tanker loading or unloading and with the above definition of a marine cargo vessel as a stationary source might attempt to regulate the vessel's activities outside the three-mile limit (but within California Coastal Waters).

It has been suggested that state and local agencies might assert regulatory control over an offshore platform by considering it an extension of an onshore facility if they are connected by a pipeline. Local or state agencies currently have jurisdiction over pipeline construction activities within the three-mile limit. Such a jurisdictional attempt would surely result in litigation. Disputes would be settled by the courts.

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IV. DESCRIPTION OF THE EXISTING ENVIRONMENT

A. Meteorology and Climatology

1. Introduction

This summary of meteorology and climatology of the offshore and coastal areas between latitudes 34° and 42° North stresses those aspects which have a bearing on the assessment of air quality effects of development of offshore petroleum resources in the 1980s and beyond. The principal consideration is the ventilating properties of the atmosphere between proposed Sale No. 53 leasing blocks and onshore areas downwind. Another consideration is the degree to which weather conditions could be hazardous to drilling, production and transportation activities. These conditions include offshore visibility and storms.

There is considerable literature on offshore and coastal meteorology. An extensive reference section has been compiled to complement this summary treatment of relevant meteorology and climatology.

Figure I-1 displays the coastal area of California considered in this study. The area lies between 34° and 42° (North) latitude. Within this area, there are four onshore coastal air basins (by legal definition). They are, from north to south, the North Coast Air Basin, the San Francisco Bay Area Air Basin, the North Central Coast Air Basin, and the South Central Coast Air Basin.

2. Climatology of the Central and Northern California Coast

a. Precipitation

There are two major mean atmospheric circulation features which affect offshore Pacific climatology. They are the Aleutian Low and the North Pacific Subtropical High. Storms are the result of the frequent passage of individual low pressure centers across the north Pacific and high pressure centers across the central Pacific. The Aleutian Low has a secondary effect, in comparison with the North Pacific High, on the climate between 34° and 42°N latitude. One effect of the Aleutian Low is the presence of a secondary storm track from the eastern Pacific to northern California during the middle and late winter months. During spring and summer, the storm tracks move northward and do not affect climatology offshore California.

The frequency of precipitation between 34° and 42°N latitude in shipping lanes is depicted in Figure IV-1 (most data from offshore observations occur in ship traffic lanes). Frequency data in this and subsequent figures represent the percentage of observations made which meet the specified condition. The frequency of precipitation drops steadily with decrease in latitude to a value of five percent off the southern California coast. No snow occurs offshore California.

There is minimal precipitation during the summer. However, the general shape of the summer precipitation frequency profile is the same as the winter profile. Off southern California, the precipitation frequency is only two percent.

Spring and autumn are transitional periods of respective decreasing and increasing precipitation frequencies. Frequency values of two to three percent occur off the California coast during these periods.

b. Humidity, Clouds, Visibility

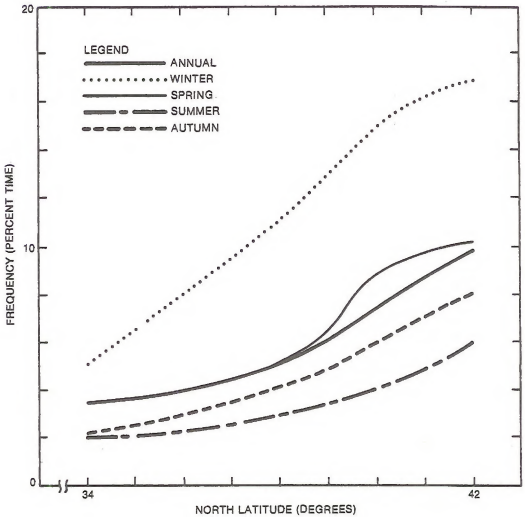
The North Pacific Subtropical High results from the slow west to east movement of anticyclones across the central Pacific. The anticyclone tracks are farthest south in winter and farthest north in late summer. This semi-permanent anticyclone has a profound influence on the climate of the eastern north Pacific. In contrast to the unstable and stormy conditions in the northern low pressure regions, the interior of the anticyclone region contains light winds and fair weather. However, on the eastern periphery of the anticyclone, persistent northerly winds in spring and summer produce an upwelling of cold ocean waters along the California coast, which in turn produces coastal fog. Strong subsidence of the air as it moves around the eastern edges of the anticyclone produces strong inversions in the lower air layers. (See Section IV.A.1.c below, for a discussion of inversions.) Stratus clouds frequently form as a result of moisture being trapped below a subsidence inversion. The inversion also forms an effective atmospheric lid which limits the vertical dispersion of pollutants that are emitted in the California coastal metropolitan areas.

The reduction of visibility to less than 2 miles over the ocean usually results from fog or precipitation. The frequency of occurrence of visibility less than 0.5 nautical miles and less than 2 nautical miles between 34° and 42°N latitude are shown in Figures IV-2 and IV-3, respectively. (Ships make visibility observations during the day and at night, when feasible.)

During winter, there is a region of maximum frequency of visibility less than 0.5 nautical miles at a midlatitude of 38°N. The frequency of occurrence is about three percent. The area of low visibility is related to a storm track which crosses the continental shelf during winter months. During the spring, the maximum disappears. During the summer, the distribution of low visibilities changes dramatically. This is caused by the northerly shift and increase in intensity of the North Pacific Subtropical High. A maximum low visibility occurrence of 5.5 percent develops near 40°N latitude. This maximum is the result of fog formation caused by warm air moving over the cold upwelling waters along the northern California coast. During the autumn, the maximum broadens, shifts southward to 38°N off the coast of San Francisco and reaches a value of six percent.

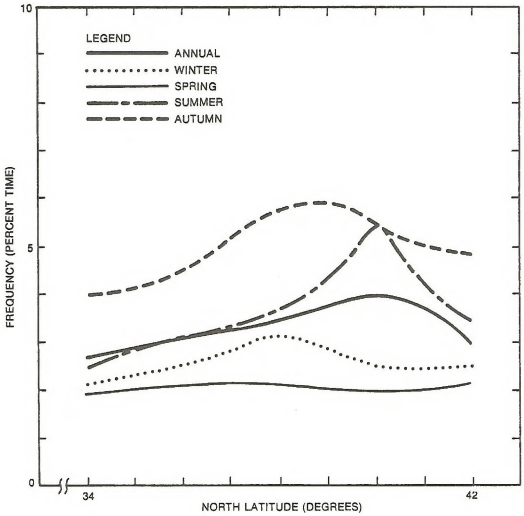
The variation of frequencies of visibility less than two nautical miles between 34° and 42°N latitude is similar to that shown by the profiles of visibility less than 0.5 nautical miles. However, the magnitude of the frequencies is greater, reaching a value of 11 percent during the summer and autumn seasons off the coast of northern California.

The relative content of moisture in air is expressed as humidity. Relative humidity is defined as the amount of water vapor present in air compared to the greatest amount that could be present at that temperature, and is expressed as a percent. One hundred percent relative humidity is generally associated with foggy conditions. Along the coast, relative humidity usually varies between 50 percent during the day to over 80 percent during the night. Over the ocean,



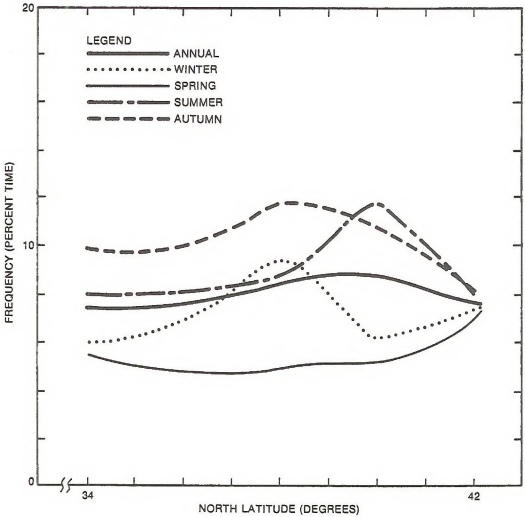
Source: Tetra Tech (1977)

Figure IV-1. PERCENTAGE FREQUENCY OF PRECIPITATION ALONG SHIPPING LANES BETWEEN 34° AND 42° NORTH LATITUDE



Source: Tetra Tech (1977)

Figure IV-2. PERCENTAGE FREQUENCY OF VISIBILITY LESS THAN ONE-HALF NAUTICAL MILE ALONG SHIPPING LANES BETWEEN 34° AND 42° NORTH LATITUDE



Source: Tetra Tech (1977)

Figure IV-3. PERCENTAGE FREQUENCY OF VISIBILITY LESS THAN TWO NAUTICAL MILES ALONG SHIPPING LANES BETWEEN 34° AND 42° NORTH LATITUDE

the diurnal variation is generally small, about four percent. Mean relative humidity is around 80 percent.

c. Inversions

A thermal inversion is a meteorological condition in which temperature increases with elevation, reversing the expected pattern of temperature decreases with increasing height above the ground. Of particular interest is a layer of air having a sudden rise in temperature with elevation. Such an inversion has low density, and possibly polluted air below, and is too dense to easily penetrate the layer. There are three types of inversions which occur in the area of interest: advective, radiational, and subsidence inversions. The subsidence inversion is common in late summer and autumn over waters offshore California, and it can persist for weeks.

The base of advective and radiational inversions is usually the ground or water surface (and the inversion is then called a surface inversion.) They generally last only several hours, but can persist longer over cold surface water. These inversion mechanisms are described further in subsequent sections.

Data on the frequency of thermal inversions over the Pacific Ocean are generally scarce or nonexistent. However, the presence of an inversion over the ocean should be highly correlated with the presence of fog and low visibility. To evaluate the validity of this relationship, a comparison of the frequencies of low visibilities and of inversions was made for the stationary ocean weather ship "P", located at 50°N latitude and 145°W longitude (Tetra Tech, 1977). The following tabulation compares the frequency of visibility less than 0.5 nautical miles with the frequency of surface inversions, and the frequency of visibilities less than two nautical miles with the frequency of inversions with bases between the surface and 1,700 feet.

	Percentage Frequency			
Season	Visibility less than 1/2 nautical mile	Surface Inversion	Visibility less than 2 nautical miles	Inversion base between surface and 1,700 feet
Winter	3	3	10	8
Spring	4	4	11	8
Summer	10	12	19	19
Autumn	4	4	9	7

The relationship appears sufficiently reliable to utilize visibility profiles shown in Figure IV-2 and Figure IV-3 to obtain approximate estimates of the percentage frequencies of inversions. Data from sea lanes should generally characterize all areas of the continental shelf. It is plausible to assume, therefore, that the highest frequency of inversions along the California coast should occur in the summer and autumn. Surface inversions should then occur with a frequency of approximately five percent, while inversions between the surface and 1,700 feet should occur approximately 11 percent of the time.

The mixing height is defined as the height above the surface through which relatively vigorous vertical mixing can occur. The height of the base of a subsidence inversion can be the mixing height. Offshore California, the mixing height is synonymous with the marine layer. In general, the marine layer is shallowest at the coast and increases in depth both landward and seaward (Noonkester, 1979).

Holzworth (1972) reports a mean annual morning mixing height of about 1,600 feet along the California shoreline between 35° and 42°N latitude (Table IV-1). The mean annual afternoon mixing height is about 2,600 feet northward as far as 40°N latitude. The value at the Oregon border is about 3,300 feet. Somewhat higher mean annual mixing heights can be assumed over the continental shelf.

d. Temperatures

The variation of the mean seasonal temperature in ship traffic lanes is displayed in Figure IV-4. The warmest temperatures and the smallest seasonal variations occur at the southern end of the range. The seasonal mean temperatures at 34°N latitude range from 56°F in the winter to 62°F in the summer, with an annual mean of 59°F. At 42°N latitude, the seasonal mean temperatures have the greatest variation. In winter, the mean temperature is 50°F, while the summer mean is about 59°F.

During the winter and spring, the mean temperatures increase from north to south along the coast. However, during the summer and autumn a shallow flat minimum occurs in the temperature profile between 38°N to 40°N latitude. This minimum is caused by the upwelling of cold ocean water along the California coast with the resultant cooling of the lower layers of air as they move over the upwelling zone.

e. Winds

South of 45°N latitude, the climatology of wind speeds offshore is controlled by the North Pacific Subtropical High. There is a seasonal variation of wind speeds which depends on the latitude. Near 45°N latitude there is a winter maximum- and summer minimum-regime. Between 45°N and 40°N latitude, there is a transitional region in which mean wind speeds show little seasonal variation. In this region, mean wind speeds at sea range from 13 to 16 knots. Between 40°N and 34°N latitude, wind speeds average 12 to 15 knots during the spring and summer and 9 to 12 knots during the autumn and winter. Extreme sustained wind speeds decrease southward. The 50-year and 100-year extreme sustained return period winds are presented in Table IV-2.

The effect of the subtropical North Pacific High on the climatology of wind directions is distinct. A persistent clockwise flow around the eastern periphery of the High results in frequent winds from the northwest to north. In the transition region (45°N to 40°N latitude), wind directions are mostly from south to southwest during the winter, but during the summer the predominant direction is from northwest to north.

3. Local Climatological Factors

a. North Coast Air Basin

Refer to Section IV.A.2, for a general description of offshore climatology and meteorology. This section summarizes climatic factors and specifics pertinent to the north coast of California. Refer to Figure III-3 for location of the North Coast Air Basin. A useful summary of climatic information pertinent to air quality considerations can be found in "Climate of the North Coast and Lake County Air Basins" (CARB, 1974).

i. Precipitation

Most storm activity and precipitation occur during the winter. In Eureka, 90 percent of annual precipitation falls between October and April. Annual totals range from 60 to 100 inches in the South and Klamath River basins, and from 40 to 60 inches in the Eel and Russian River basins to the south. Frontal systems bring rain lasting from a few days to as much as two weeks. Dry weather usually follows. Longer periods of rainfall are usually associated with a temporary northward movement of the North Pacific High, which may be coupled with a strong surface ridge over the Great Valley to the east. The synoptic pattern acts to block passage of fronts into central California. Under these conditions, frontal systems stagnate in the North Coast Air Basin. With the onset of spring, the North Pacific High pressure cell shifts northward, steadily strengthens, and tends to block storm fronts.

ii. Humidity, Clouds, Visibility

During fair periods in autumn or winter, nighttime cooling leads to formation of ground fog in sheltered inland valleys. Stagnation accompanies these fogs when they persist for several days. These conditions are most common toward the south end of the North Coast Air Basin.

During summer, relatively warm air passes over a 25 to 30 mile wide band of cool (about 52-55°F) water. The air mass is cooled near the water surface, forming a deck of coastal fog or stratus. The visibility reducing moisture is evaporated a few miles inland during the day. The moisture laden air extends further inland at night. As a result, less than 50 percent of incident solar radiation reaches the surface of Eureka during the summer.

iii. Inversions

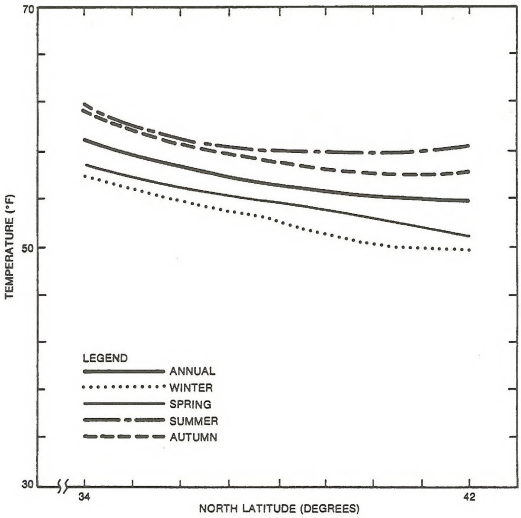
Table IV-3 summarizes results of soundings taken in the North Coast Air Basin. The 8 a.m. and 8 p.m. soundings at Arcata result in similar percentages of surface and elevated thermal inversions. It appears that the effects of daytime heating in dissipating the inversion do not last very long since the evening sea breeze regime soon dominates again. The morning inversions at Ukiah show surprisingly little variation with the seasons. Nearly all soundings had surface-based inversions. The fall morning soundings taken at Eureka show the same distribution as those at Ukiah.

The only winter temperature inversion data available for the air basin are from the California Air Resources Board's (CARB) Ukiah aircraft flights (Table IV-3). During days on which morning aircraft temperature soundings were

Table IV-1. AVERAGE MIXING HEIGHTS INTERIOR REGIONS OF SOUTH CENTRAL COAST AIR BASIN (1968-1970)

	---Winter------ (Dec-Jan-Feb)		--Spring---- Mar-Apr-May)		---Summer----- (Jun-July-Aug)		-----Fall---- (Sep-Oct-Nov)		Annual	
	0400 P.S.T.	1600 P.S.T.	0400 P.S.T.	1600 P.S.T.	0400 P.S.T.	1600 P.S.T.	0400 P.S.T.	1600 P.S.T.	0400 P.S.T.	1600 P.S.T.
Average Mixing Heights (feet)	1,300	3,000	2,000	4,000	1,300	3,000	1,300	3,000	1,300	3,600

Source: U.S. Environmental Protection Agency, AP-101 (Holzworth, 1972).



Source: Tetra Tech (1977)

Figure IV-4. SEASONAL AND ANNUAL MEAN AIR TEMPERATURES IN SHIPPING LANES BETWEEN 34° AND 42° NORTH LATITUDE

Table IV-2. EXTREME SUSTAINED WIND SPEEDS (KNOTS) OFFSHORE

Latitude	50 Year Return	100 Year Return
45-40°N	88	95
40-37°N	86	93
37-34°N	75	82

Source: Tetra Tech (1977).

Table IV-3. NORTH COAST AIR BASIN INVERSION SUMMARY*

Location/Period	Season	Time (PST)	Percent of Soundings with: Surface Inversion	Elevated Inversion	No Inversion	Total Number of Soundings
ARCATA (Apr-Nov '45)	Apr-May	0800	3	50	47	38
	Jun-Aug		37	51	12	49
	Sep-Nov		35	37	28	51
	Apr-May	2000	3	52	45	33
	Jun-Aug		31	53	16	51
	Sep-Nov		36	39	25	44
EUREKA (Oct-Nov '71)	Oct-Nov	0600	82	15	3	40
UKIAH (Oct-Nov '71) (Nov '72-June '74)	Mar-May	0500	87	11	2	173
	Jun-Aug		84	16	0	119
	Sep-Nov		89	9	2	129
	Dec-Feb		80	20	0	131

Notes: *Soundings from the surface to 5,000 feet.
Source: California Air Resources Board (1974).

taken, surface-based inversions existed 80 percent of the time, while elevated inversions existed the rest of the time.

In the spring months, along the coast, the sparse Arcata data show that about half of all soundings had either no inversion or only an elevated inversion. The inland soundings taken in the mornings at Ukiah on the other hand, showed mainly (87 percent) surface-based inversions.

At Arcata, there are considerably more surface-based inversions during the summer than in the spring (37 versus 3 percent). Inland at Ukiah, on the other hand, there is a consistently high frequency (80 to 89 percent) of morning surface-based inversions.

The most adverse air pollution conditions in the North Coast Air Basin are associated with a weak, shallow, marine air flow, or with a prolonged period of weak pressure gradient and clear sky conditions. The relatively long dry periods of July through October coincide in general with the weakest air flow and moderately frequent presence of surface or elevated inversions.

iv. Temperatures

The ocean acts as a temperature-moderating heat sink. Temperatures seldom fall below freezing along the coast during winter. Ground fog and marine layer stratus also depress maximal summer temperatures. Summer temperatures are consistently below 80°F near the coast. The highest coastal temperatures occur during September.

v. Winds

In the winter, there are occasional strong gusty northerly winds (refer to Table IV-2, above) and ventilation is generally good. Spring is a transitional period, with the direction of the prevailing wind shifting from southeast to north to northeast. The prevailing wind is from the northwest during the summer. Wind directions inland, however, are influenced by terrain. Synoptic pressure gradients are generally weak during autumn. As a result, lowest mean wind speeds occur in August through October.

b. San Francisco Bay and North Central Coast Air Basin

Refer to Figure III-3 for the location of the San Francisco Bay and North Central Coast Air Basins. A summary of climatic information useful to air quality considerations can be found in "Climate of the North Central Coast Air Basin" (CARB, 1975a).

i. Precipitation

During winter, the North Pacific Subtropical High weakens and shifts southward. This allows storms developing in the North Pacific to penetrate as far as the North Central Coast Air Basin. Winter weather is not severe. As in the North Coast Air Basin (section IV.A.3.a), a stagnation condition can occur bringing extended rainy weather. Fall and spring are transitional seasons. In the fall, westerly winds shift southward and frontal passages may produce showers or rain. Table IV-4 presents a summary of weather data recorded at Fort Ord. Monthly mean and maximum daily precipitation are included in the summary.

ii. Humidity, Clouds, Visibility

During the summer, air is compressionally heated, which lowers relative humidity and precludes rain. However, the passage of air over water often results in fog or stratus in the surface layer. A thermal trough is sometimes present in the California interior which permits strong pressure gradients to carry marine air through the Carquinez Straits, as well as into coastal valleys. West of San Francisco, the zone of upwelling cold water is estimated to be 80 miles wide (CARB, 1975a). The coldest water is just north of San Francisco in July and moves further northward in August and September. There is a corresponding shift in density of fog and marine stratus northward during the summer. This marine influence on the coast is lessened or neutralized when the pressure gradient is reversed. If the synoptic pressure in the interior of California is sufficiently strong, compressional heating lowers the relative humidity and results in clear skies. Refer to Table IV-4 for monthly early morning and afternoon relative humidity averages, average number of days with fog, and relative cloud cover annually and by month.

iii. Inversions

Table IV-5 presents results of aircraft temperature soundings at Salinas. Mean morning mixing heights were found to range from 1,100 feet during the winter through 1,700 feet during the summer. The greatest variability in mixing heights was noted during the spring. The atmosphere is more frequently unstable during this period.

iv. Temperatures

The climatology of surface temperatures is significant in determining the ventilating capacity of the San Francisco Bay and North Central Coast Air Basins. There is often enhanced ventilation on summer afternoons when a large temperature differential exists between cool coastal water and heated land surfaces. The flow inland is strongly influenced by terrain features. Flow is both through terrain channels and up thermally heated slopes. The temperature gradient is relatively weak where the marine flow is not impeded, into a large, flat coastal basin, for example. Very strong temperature gradients occur in areas where the coastal mountain range is near the shoreline.

In Figure IV-5, tne average maximum surface temperatures for July 1973 are plotted. A relatively large area of uniform temperatures occurs in the broad coastal plain east of Monterey Bay. The marine air is modified as it moves southeastward in the Salinas Valley, with a 17°F increase in the average maximum surface temperature between Salinas and King City.

The marine air is warmed even more rapidly as it flows eastward from the coastal area up the Pajaro River valley to Hollister. Here, the marine flow is more restricted by terrain features.

Large differences in diurnal and annual temperatures are an indication of a continental-type climate. In these basins, there is a transition between the marine climate near the coast, with small diurnal and annual temperature changes, and the continental climate of inland areas, with hotter summers and cooler winters. Refer to Table IV-4 for monthly temperature data recorded at Fort Ord.

Table IV-4. CLIMATIC SUMMARY- FORT ORD (1960-1970)

	Temperature (°F)				Precipitation (inches)		Wind (knots)			Relative Humidity		Mean Number of Days		
Month	Extreme Maximum	Daily Maximum	Daily Minimum	Extreme Minimum	Mean Total	Maximum in 24 Hours	Prevailing Direction	Mean Speed	Extreme Speed	0400 PST	1300 PST	Thunder-storms	Fog (7 miles)	Mean Cloud (Tenths)
Jan	79	60	37	23	2.9	1.7	E	5	44	83	57	#	13	5
Feb	76	60	42	24	2.0	1.9	W	5	50	87	57	#	13	6
Mar	81	59	41	28	2.1	1.8	W	5	37	85	59	#	10	5
Apr	91	61	45	33	2.0	1.5	W	6	40	82	60	0	11	5
May	89	61	48	38	0.2	0.3	W	7	40	87	65	#	13	6
Jun	85	63	51	40	0.1	0.2	W	7	38	88	67	#	18	6
Jul	82	64	52	41	0.1	0.7	W	7	26	90	69	#	24	6
Aug	91	64	53	45	#	0.2	W	7	28	93	71	0	25	6
Sep	93	68	52	36	0.1	0.3	W	5	29	89	64	1	20	5
Oct	103	69	48	34	0.4	0.7	W	5	40	85	58	#	17	5
Nov	90	63	44	28	2.1	1.9	E	4	42	85	59	#	16	5
Dec	77	59	39	26	2.2	1.5	E	4	42	84	60	#	11	5
Annual	103	63	46	23	14.2	1.9	W	6	50	87	63	1	191	5

*Data not available. #Less than 0.5 day, 0.5 or 0.05 inch, or 0.5 percent (%) as applicable.

Source: U.S. Air Force, Climate Briefs, 1967.

Table IV-5. MEAN MORNING MIXING HEIGHTS - SALINAS, CALIFORNIA (OCTOBER 1971 - APRIL 1974)

Season	Average Height (Feet)	Standard Deviation (Feet)
Winter	1,120	912
Spring	1,650	1,140
Summer	1,740	850
Fall	1,263	745

Source: California Air Resources Board (1975a).

Table IV-6. PERCENT FREQUENCY ONSHORE AND OFFSHORE FLOW OF MONTEREY

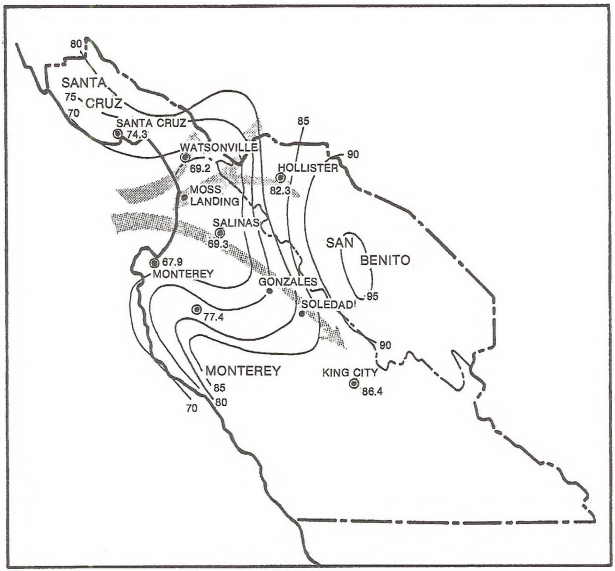
	Highest Percentage Offshore Flow (SE)	Highest Percentage Onshore Flow (NW)
January	19% at 0600 PST	23% at 1300 PST
July	5% at 0500 PST	34% at 1400 PST

Source: California Air Resources Board (1974).

Table IV-7. MEAN MORNING WIND SPEED IN THE MIXING LAYER SALINAS, CALIFORNIA (OCTOBER 1971 - APRIL 1974)

Season	Average Wind Speed (meters/second)	Standard Deviation (meters/second)
Winter	4.9	2.8
Spring	4.6	2.6
Summer	4.9	2.2
Fall	4.6	2.6

Source: California Air Resources Board (1975a).



Source: California Air Resources Board (1975a)

Figure IV-5. AVERAGE MAXIMUM SURFACE TEMPERATURE (°F) FOR JULY 1973 IN THE NORTH CENTRAL COAST AIR BASIN

v. Winds

Three physical phenomena determine wind characteristics along the California coast, especially south of San Francisco. The largest scale phenomenon is the periodic, synoptic atmospheric pressure pattern. Superimposed on the synoptic pattern are diurnal and annual thermal pressure gradients resulting from heating or cooling of the ground relative to the ocean (the second, or thermal phenomenon). The diurnal pattern involves warming of air near heated ground during the day, often followed by cooling of the ground and surface air on cool, cloudless nights. This creates a frequent pattern of a sea, or onshore, breeze (flow toward shore) during the day, sometimes followed by a weaker land (offshore) breeze at night. The sea breeze reaches its maximum speed during the afternoon. The third, and most local, phenomenon is channeling of the pressure-induced flow past terrain features. A case significant for offshore emissions, which involves the interaction of these phenomena, was described in the previous section (Section IV.A.3.b.iv).

In Santa Cruz County, coastal mountains exert a strong influence on atmospheric circulation and result in generally good air quality. Small inland valleys such as Scotts Valley, with low mountains on two sides, have poorer circulation than at Santa Cruz on the coastal plain. Scotts Valley is downwind of major pollutant generating centers and these pollutants have time to form oxidants while in transit to Scotts Valley. Consequently, air pollutants tend to build up much more at Scotts Valley than at Santa Cruz.

The seasonal distribution of surface winds, typical of the North Central Coast Air Basin, is illustrated in Table IV-4. During the months of November, December, and January, the prevailing wind direction is from the east. During the remainder of the year, the prevailing wind direction is from the west. This reversal illustrates the general synoptic pattern, coupled with the annual thermal pattern.

The diurnal and seasonal wind climatology are illustrated in Table IV-6. The data are extracted from the summary of aerological records from Monterey Naval Air Station.

A surface wind at 1400 PST from an easterly quadrant is infrequent during July, occurring less than two percent of the time. Onshore flow is more frequent than offshore flow throughout the year. Table IV-7 presents mean season surface wind speeds. The mean speed differs little throughout the year.

c. South Central Coast Air Basin

A useful summary of climatic information can be found in "Climate of the South Central Coast Air Basin" (CARB, 1975b). Refer to Figure III-3 for location of the South Central Coast Air Basin. The general climatological factors pertinent to the air basin are described in previous subsections.

i. Precipitation

The period from November through April is relatively wet and cool, with about 90 percent of annual precipitation occurring in these months. Annual precipitation averages about 6 inches at some inland measuring stations and about 30 inches in the higher mountains in the southeastern portion of the air basin. Storms which approach the basin from the southwest carry significant

amounts of subtropical moisture and can produce heavy rains and flooding. Storms from the northwest are cooler, but generally result in lighter rainfall (or even snow). Local rainfall is affected by terrain characteristics. Near the coast there are about 45 days each year with measurable precipitation.

ii. Humidity, Clouds, Visibility

Sunshine is abundant over most of the air basin. Along the coast and in western valleys, there is frequent low cloudiness during night hours in the summer. Fog is reported along the coast about 20 percent of the time during the summer. The area averages about 70 cloudy days each year.

iii. Inversions

There are only limited data available on the frequency of occurrence of inversions in the South Central Coast Air Basin. Inversion conditions along the coast can be inferred from the data for Vandenberg Air Force Base tabulated in Table IV-8.

In general, the frequency of low inversions is greater in the morning than during the afternoon along the coast. Heating by the sun tends to lift the inversion base as the day progresses. Mixing heights in the interior show this same diurnal trend. Along the coast, the sea breeze regime generally maintains mixing heights below 2,000 feet during afternoons.

iv. Temperatures

As a result of rugged terrain and the proximity of the Pacific Ocean, temperatures vary considerably over the air basin. In general, temperatures are mild along the narrow coastal plain, with small daily and annual ranges. Inland, particularly in the valleys, temperature fluctuations are rather large because of the predominance of clear skies which provide a high potential for daytime solar heating and nighttime radiational cooling.

There is sea breeze cooling in summer, which decreases with distance inland. Figure IV-6 plots the increase of maximum temperatures from west to east in the area north of the San Ynez mountains. July maximum temperatures average 65° to 73°F along much of the coast and in the coastal valleys. In the interior valleys and plains maximums range from 90° to 98°F. Figures are not available for higher elevations, but it appears likely that most mountain areas have maximum temperatures of 80° to 98°F during July. All stations in the basin, except for those along the coast, have reported summer afternoon temperatures of over 100°F -- some as high as 117°F. Nighttime average minimum temperatures in July are 50° to 55°F over most of the basin, making the diurnal temperature change quite extreme in the interior.

In January, the average minimum temperatures range from 42° to 49°F along the coast, decreasing to near freezing in the interior valleys and plains. In some of the higher mountain areas, January low temperatures average below the freezing mark.

v. Winds

Synoptic pressures produce a regional, prevailing northwesterly to westerly flow throughout the year. During the winter, the basic flow reverses to a

prevailing southeasterly direction under conditions of pre-storm passage. Except for the coastal zone, the rugged and varied terrain of the area is responsible for deflecting the basic flow, so that wind direction and wind speed within the area are mostly a result of local terrain influences, rather than of prevailing circulation.

The wind regime along the exposed coastline and on the mountain ridges in the area generally conforms closely to that of the basic circulation since terrain influences are minimal at these locations. In major valleys, the wind direction is highly biased to the general orientation of the particular valley. Wind behavior in the smaller valleys in the area is complex, but is influenced by the prevailing wind direction, the solar angle, and terrain features.

In general, wind speeds are light throughout the year during the hours of darkness, when the atmosphere is cooling and stabilizing. Exceptions occur on exposed ridges, along the coast, or when strong storms and frontal systems are present.

Wind speeds generally increase during the day and peak in the afternoon. The strongest winds accompany winter storms. Estimates, based on available wind records, suggest that speeds of 60 miles per hour may be experienced no more than once in 50 years over most of the area. (Refer to Table IV-2 for maximum wind speeds offshore.)

4. Modeling Meteorology

Air pollution modeling is used to predict air pollution effects from projects anticipated to occur in future years. This study utilizes models for both inert air pollutants and reactive air pollutants. The meteorological conditions which result in highest inert concentrations are not necessarily identical to those which result in highest secondary air pollutant concentrations. (Secondary pollutants are products of reactions in the atmosphere.) Consequently, meteorological conditions which result in highest concentrations must be identified for each type of modeling. Simpler Gaussian models, devised for inert pollutants, require fewer parameters and assumptions (refer to Appendix D for a general discussion of the models and the modeling methodologies). Current methodologies for inert or primary pollutant assessments in coastal areas use the simpler Gaussian models to screen for highest feasible pollutant concentrations. If the anticipated increments to ambient concentrations are acceptably low, further modeling is not required. Otherwise, more sophisticated models must be used and more realistic meteorological conditions specified. Special models for simulating atmospheric chemical reactions are used for reactive pollutants.

a. Meteorological Factors for Worst Cases

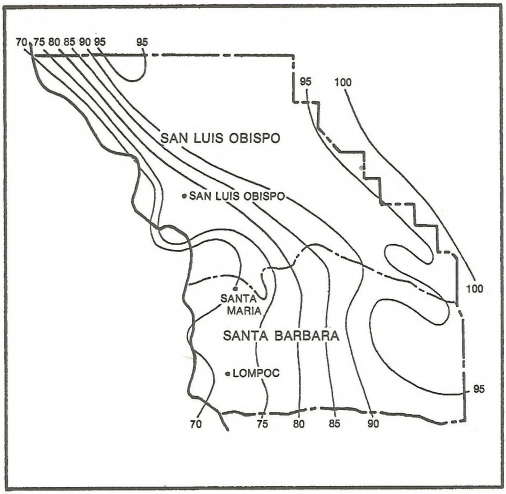
This section briefly describes the meteorological assumptions appropriate for Gaussian screening modeling. Attention then turns to the meteorological factors and trajectories, insofar as they can be specified from current data, which should result in highest air pollution concentrations onshore.

In order to achieve worst case inert concentrations during summer sea breeze conditions, stable atmospherics, a low inversion height, a low wind speed, and direct unwavering transport from offshore to onshore are assumed. Available

Table IV-8. PERCENTAGE FREQUENCY OF OCCURRENCE OF INVERSION CONDITIONS AT VANDENBERG AIR FORCE BASE (1969-1970)

Height of Inversion Base (Feet MSL)	---Winter------ (Dec-Jan-Feb)		--Spring---- Mar-Apr-May)		---Summer----- (Jun-July-Aug)		-----Fall---- (Sep-Oct-Nov)		Annual	
	0400 P.S.T.	1600 P.S.T.	0400 P.S.T.	1600 P.S.T.	0400 P.S.T.	1600 P.S.T.	0400 P.S.T.	1600 P.S.T.	0400 P.S.T.	1600 P.S.T.
0-500	83	7	65	1	26	1	58	3	58	3
501-1000	3	17	7	29	20	30	8	38	10	29
1001-2000	3	20	14	38	41	55	21	36	20	37
2001-3000	2	9	9	7	8	8	5	6	6	7
3001-4000	1	13	1	6	3	4	4	5	2	7
4000	8	34	4	19	2	2	4	12	4	17

Source: California Air Resources Board (1975b).



Source: California Air Resources Board (1975b)

Figure IV-6. AVERAGE MAXIMUM TEMPERATURES (^{o}F) FOR JULY IN SAN LUIS OBISPO AND NORTH SANTA BARBARA COUNTIES

data (Bennett, 1979 and Schacher, 1978) support the assumption of a slightly stable (Pasquill stability class E) atmosphere over the ocean. Wind speed and inversion data (See Section IV.A.2 and IV.A.3) complete the Gaussian meteorological input. Gaussian modeling is discussed in Chapter VI.

The production of ozone from Lease Sale No. 53 emissions is the modeling situation of principal concern. It is assumed that maximal OCS-related onshore ozone concentrations will occur under meteorological conditions similar to those of presently measured high onshore ozone. It is further necessary that the polluted air which ultimately yields high ozone levels pass over an OCS area. Thus, the assessment requires the development of trajectories whereby polluted air passes over an OCS activity area and then moves onshore to monitoring sites.

The modeling results using constructed trajectories are meant to serve as upper bounds of potential air pollutant impacts. Historical data from past episodes should be used in documenting trajectories. The required data, however, are very sparse or non-existent; and trajectories, therefore, must be developed with a great deal of subjectivity. For cases with minimal data, trajectories are developed to give conservative, or "worst case" results, provided the trajectories are consistent with the available data. For a conservative result, the air flow of a trajectory should (1) pass over an OCS area, (2) spend a considerable length of time pooling in the OCS area overnight and in early morning hours, and (3) arrive at an onshore point of measured high ozone (i.e. a monitoring station). (High ozone herein refers to the highest monitored ozone levels for each air basin or county as reported in the relevant maintenance or implementation plan documents.) Some populated onshore areas could not be associated with airflow from a Lease Sale No. 53 offshore OCS block coincident with historically observed high ozone.

The general methodology which is used to develop trajectories begins with compilation and analysis of existing reports describing coastal zone photochemical air pollution. The depth of these reports ranges from the comprehensive Bay Area studies to the relatively limited air quality maintenance documents for the North Coast Air Basin. In general, the amount of data is proportional to the magnitude of the local photochemical air pollution problem. Measured local high ozone data in these reference sources help in determining the associated meteorological conditions. Possibilities for concurrent air flow from an OCS area to an onshore point of concern are determined. A specific occurrence is selected, all readily available relevant data are compiled, and the trajectory and model input data are then developed.

The required modeling input data include: wind speed, stability and inversion height hourly along the trajectory; initial ambient pollutant loading at the start of the trajectory; and hourly entrained emissions. The final ozone measurement is used to verify the baseline modeling. The compiled data, which were available to develop the meteorological input data, ranged from detailed hourly streamline maps and temperature soundings to generalized over-water wind patterns. Where specific, relevant data were lacking, the following assumptions were used:

1. The initial pollutant concentrations were taken from offshore Marine Atmospheric Boundary Layer Experiments (MABLES) data (Bennett, 1979) and were later adjusted within reasonable limits to match the ending ozone;

2. Stability Class over the ocean was assumed to be stable for offshore flow and neutral for onshore flow;

3. Inversion heights began at 100 meters over water and rose to as much as 600 meters over land for early afternoon; and

4. Onshore emissions were taken from emission inventories in Air Quality Maintenance Plans and were roughly apportioned by urban population density along the overland section of each trajectory.

b. Worst Case Trajectories

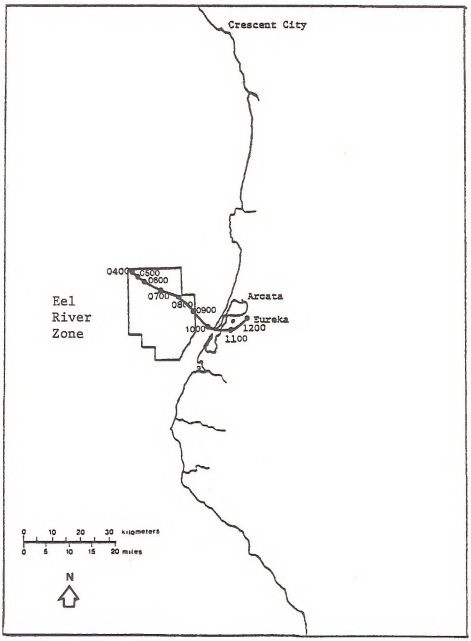
The coastal counties of the North Coast Air Basin (Humboldt and Mendocino) are in attainment of ozone and nitrogen dioxide air quality standards. Consequently, ozone measurements are sparse. Some ozone measurements were collected over a two year period in Humboldt County, but no special studies of value to photochemical modeling were obtained for these counties. As a result, there are insufficient meteorological data to serve as a basis for dated air flow construction. Two hypothetical trajectories have been constructed which pass over the OCS areas and terminate at population centers.

The trajectory starting at the Eel River OCS block (Figure IV-7) was developed to represent a maximum potential for oxidant and nitrogen dioxide formation at Eureka. This trajectory corresponds well with prevailing wind structure. Lowest possible wind speeds and highest stability were assumed.

The Point Arena trajectory (Figure IV-8) corresponds to less frequent northward flow after extensive pooling over the OCS zone between Point Arena and Fort Bragg. This meteorological structure is justified on the basis of data recorded by U.S. Navy ships (U.S. Navy, 1976b). Maximum modeled ozone values should also result using this trajectory. The trajectory could be reflected about an axis perpendicular to the coast. With all other modeling inputs the same, onshore impact would be identical. The trajectory would have greater frequency of occurrence but would impact a less populated onshore area. The frequency of occurrence of the meteorological conditions in the Eel River (Eureka) and Point Arena (Fort Bragg) trajectories is low; this is discussed further in Section IV.A.4.c below. Meteorological and ambient air quality modeling inputs for all trajectories are tabulated in Appendix C.

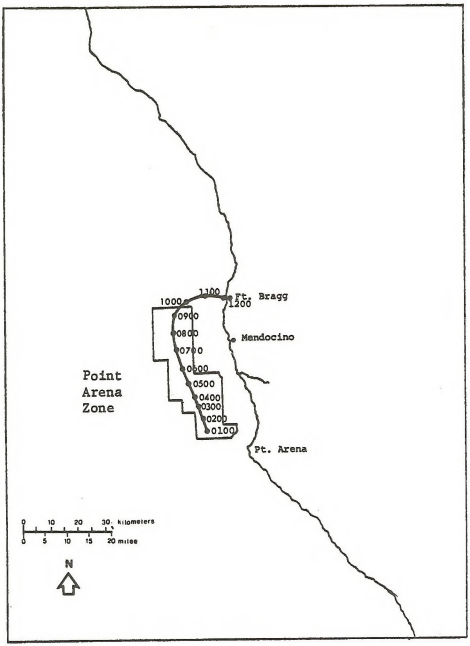
The Bodega OCS zone off Marin County and the Santa Cruz zone off Monterey County could both generate emissions reaching the San Francisco Bay area. A total of seven trajectories were developed from extensive Bay Area Air Quality Management District (BAAQMD) analyses to assess the range of potential impacts (Robinson and Sanberg, 1979). The large Bay Area population and associated production of emissions explains the compilation of the sophisticated, existing data base for the area.

The first four trajectories span the distance between the Bodega OCS zone and the Bay Area. Two trajectories (Figures IV-9 and IV-10) assess flow through the Petaluma gap while the other two (Figures IV-11 and IV-12) involve flow into the Bay. August 22, 1974 (Figure IV-9) was selected because of the flow pattern



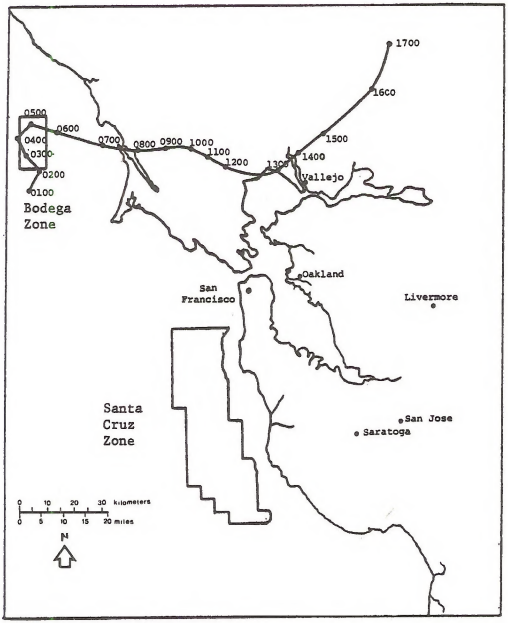
[Numbers along trajectory - e.g. 0500 - refer to time (PST) of day]

Figure IV-7. EEL RIVER (EUREKA) PHOTOCHEMICAL MODELING TRAJECTORY



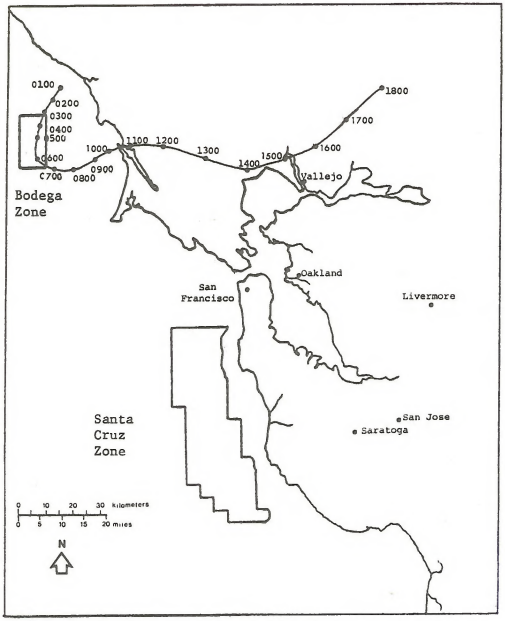
[Numbers along trajectory - e.g. 0500 - refer to time (PST) of day]

Figure IV-8. POINT ARENA (FT. BRAGG) PHOTOCHEMICAL MODELING TRAJECTORY



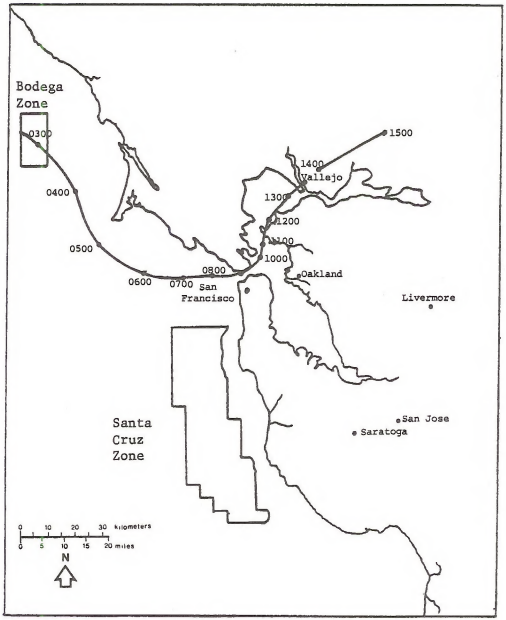
[Numbers along trajectory - e.g. 0500 - refer to time (PST) of day]

Figure IV-9. SAN FRANCISCO BAY AREA PHOTOCHEMICAL MODELING TRAJECTORY #3 FOR AUGUST 22, 1974, WITH 9 ppbm O_3 MEASURED AT VALLEJO AT 1400 HOURS



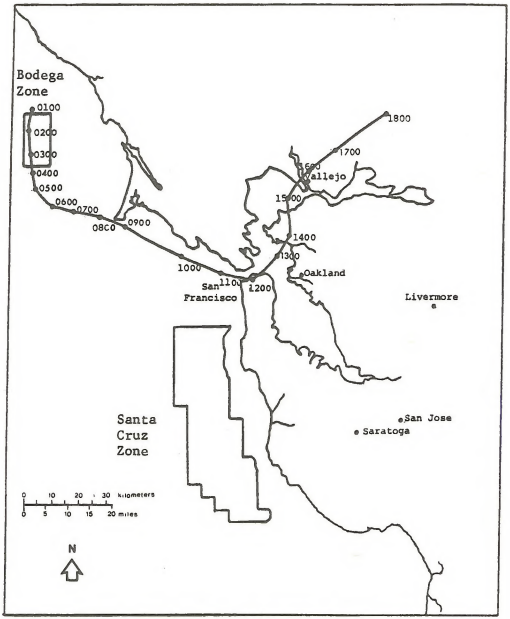
[Numbers along trajectory - e.g. 0500 - refer to time (PST) of day]

Figure IV-10. SAN FRANCISCO BAY AREA PHOTOCHEMICAL MODELING TRAJECTORY #5 FOR SEPTEMBER 9, 1976, WITH 3 pphm O_3 MEASURED AT VALLEJO AT 1500 HOURS



[Numbers along trajectory - e.g. 0500 - refer to time (PST) of day]

Figure IV-11. SAN FRANCISCO BAY AREA PHOTOCHEMICAL MODELING TRAJECTORY #4 FOR JULY 26, 1973 WITH 10 pphm O_3 MEASURED AT VALLEJO AT 1400 HOURS



[Numbers along trajectory - e.g. 0500 - refer to time (PST) of day]

Figure IV-12. SAN FRANCISCO BAY AREA PHOTOCHEMICAL MODELING TRAJECTORY #7 FOR SEPTEMBER 9, 1976, WITH 8 pphm O_3 MEASURED AT VALLEJO AT 1600 HOURS

and by reason of its previous analysis as part of LIRAQ modeling (LLL, 1975). A trajectory for July 26, 1973 (Figure IV-11) was also selected for comparison with LIRAQ modeling. The use of September 9, 1976 (Figures IV-10 and IV-12) provides trajectories with possible atmospheric recirculation.

The final three trajectories focus on flows starting at the Santa Cruz OCS zone. Two trajectories, shown in Figures IV-13 and IV-14, are based on meteorology from August 5, 1978 and use the MABLES data (Bennett, 1979). To develop these trajectories, a strong shear was hypothesized so that a northward flow near the coast would transport air across the OCS area and into the Bay area (a flow from the northwest was observed further west (Schacher, 1979) while onshore winds from the southwest were being measured).

For August 5, 1978, the divergent flow into the Bay provides a possible projection of the trajectory toward Livermore (measured ozone was 0.15 ppm) or Saratoga (measured ozone was 0.20 ppm).

Another trajectory (Figure IV-15) was selected because of its previous extensive use in Bay Area modeling studies involving the LIRAQ model. The study day (July 26, 1973) provides a valuable cross check of the modeling effort.

Two potential OCS ozone-producing trajectories were developed for the Monterey Bay area. These trajectories pass through the Santa Cruz OCS zone. The first is based on the detailed relevant MABLES data for August 5, 1978 (Bennett, 1979; Schacher, 1979). It passes through the OCS area with high wind speed and ends in Salinas at 1100 PST with an ozone measurement of 0.03 ppm (Figure IV-16). This trajectory, though not corresponding to high ozone, is one of the few for which detailed initial pollutant concentrations are known.

The second trajectory (Figure IV-17) involves lower wind speeds and high measured ozone. The surface wind data suggest transport from the OCS zone to Scotts Valley where the historical ozone high (0.21 ppm) was measured. The second high occurred nearby at Aptos (0.13 ppm) on the same day. This trajectory is interesting because of the potential atmospheric recirculation pattern and the high ozone at the end of the trajectory. The trajectory is largely conjectural and is based on the observed offshore flow after midnight in the Bay Area coupled with potential north to northwest winds at sea.

The largest estimated OCS Lease Sale No. 53 resource area is off Santa Barbara and San Luis Obispo Counties. It is called the Santa Maria zone and is 125 miles south of the Santa Cruz zone. This considerable distance suggests that the Santa Cruz zone is not likely to have a measurable effect upon the South Central Coast Air Basin. It is also unlikely that the Santa Maria OCS zone will affect the North Central Coast Air Basin because of the prevailing northwest surface winds.

In discussions with the San Luis Obispo Air Pollution Control District (SLOAPCD) (Carr and Allen, 1979), it was decided to focus on the high ozone (0.14 ppm) episode monitored at Nipomo on September 29, 1978. Nipomo is about nine miles inland on the coastal plain. This case has fewer terrain complexities than would be encountered in modeling a trajectory ending in San Luis Obispo. Nevertheless, it retains most of the potential OCS impact character (transport time and overland time). Nipomo has a higher historical ozone level than San Luis Obispo (0.14 versus 0.11 ppm).

The wind flow leading to the observed 0.14 ppm ozone in Nipomo at 1500-1600 PST was from the northwest and was projected out over the ocean (Figure IV-18). (An alternative flow could have been hypothesized as coming from a more northerly direction past San Luis Obispo; terrain effects and limited meteorological data result in considerable uncertainty.) The winds were calm until 0700 PST, allowing for minimal dilution of OCS emissions over the OCS block. The initial meteorological and air quality conditions were assumed to be similar to those measured off San Francisco during the MABLES study (Bennett, 1979; Schacher, 1979). Local early morning data, however, suggest much higher ambient pollutant levels (0.11 ppm NO; 0.08 NO_2; and 3.4 ppm total hydrocarbons). Both sets of initial conditions were tested.

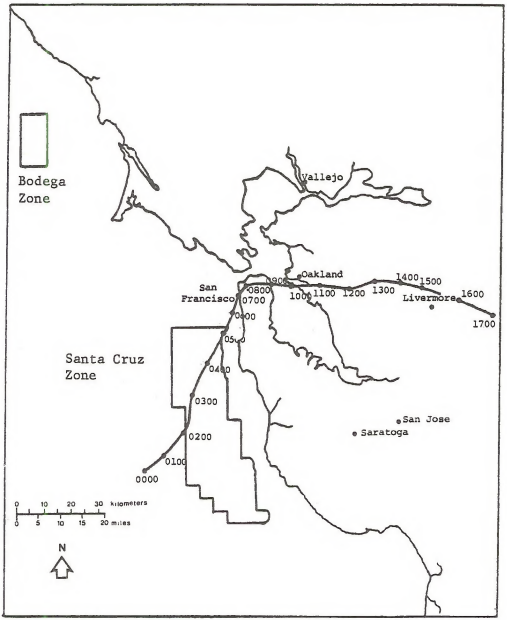
Three areas of Santa Barbara County were identified as candidates for potential OCS ozone production: South Coast (which includes Santa Barbara), Santa Ynez, and Santa Maria (refer to Figure IV-19 for locations). A lengthy overwater path is required for Santa Maria Zone OCS emissions to reach the South Coast. Santa Ynez is 30 miles from the shore and represents the potential for continued emissions reactions along the lengthy overland path. Santa Maria is in the north coastal plain. These three areas, therefore, represent a variety of potential ozone-producing conditions.

The South Coast had high ozone readings (up to 0.25 ppm) on June 26, 1975. However, a review of this day and of June 25, 1976 (with 0.22 ppm) failed to establish meteorological conditions consistent with air flow from the OCS area to the South Coast. Working from the opposite tack, the few analyzed days that showed flow from the OCS area led to low ozone in the South Coast area. Since the OCS link is essential, one of these latter days, June 20, 1978, was selected. The ozone at Goleta was 0.03 ppm at 1400 PST. The trajectory developed is shown in Figure IV-20. The length of time in the OCS area was conservatively estimated for maximum entrainment of OCS emissions.

The Santa Ynez station measured a high ozone level of 0.15 ppm at 1300 PST on June 5, 1977. This high-ozone air can be traced backwards toward the coast (assuming it was part of the sea breeze and did not result from fumigation to the surface of ozone aloft). The trajectory is illustrated in Figure IV-21. The over-water air flow has been optimized, as in all three of these trajectories, for extended length over the OCS area.

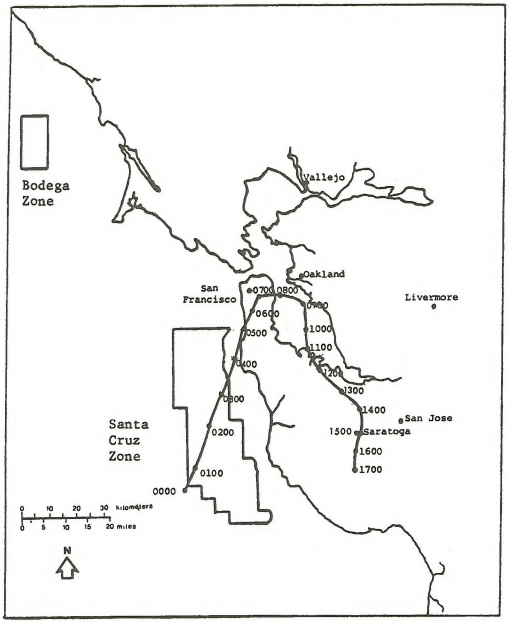
Santa Maria had a highest ozone reading of 0.12 ppm at noon on July 30, 1977, with air flow from the northwest. A trajectory analysis backwards in time resulted in a trajectory extending to the OCS area, as shown in Figure IV-22.

Each of these trajectories has a hypothesized long stay over the Santa Maria zone to maximize emissions entrainment. The baseline meteorological and air quality modeling inputs for each trajectory are tabulated in Appendix C. Since all trajectories begin offshore, the initial pollutant loading cannot be determined from measurements. Initial conditions were adjusted (within reasonable bounds) to result in the measured ozone at the terminus of each trajectory. Inversion heights were estimated from Vandenberg soundings (Table IV-8). The onshore emissions were simply estimated by apportioning the AQMP emissions inventories in proportion to population densities. Modeling methodologies and results are discussed in Chapter VI and Appendices B and D.



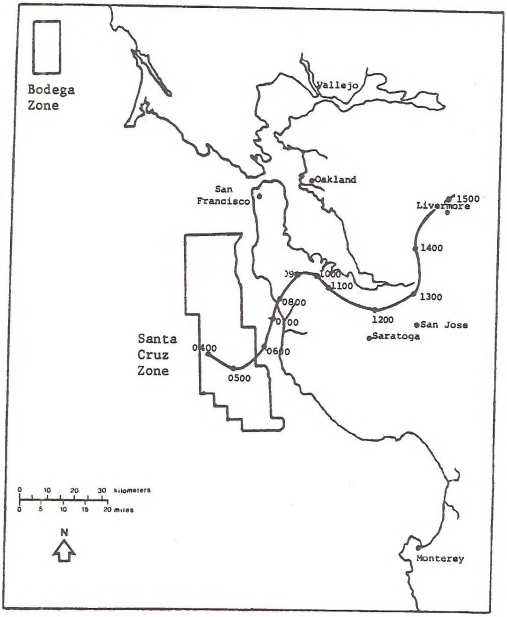
[Numbers along trajectory - e.g. 0500 - refer to time (PST) of day]

Figure IV-13. SAN FRANCISCO BAY AREA PHOTOCHEMICAL MODELING TRAJECTORY #1 FOR AUGUST 5, 1978, WITH 15 pphm O_3 MEASURED AT LIVERMORE AT 1500 HOURS



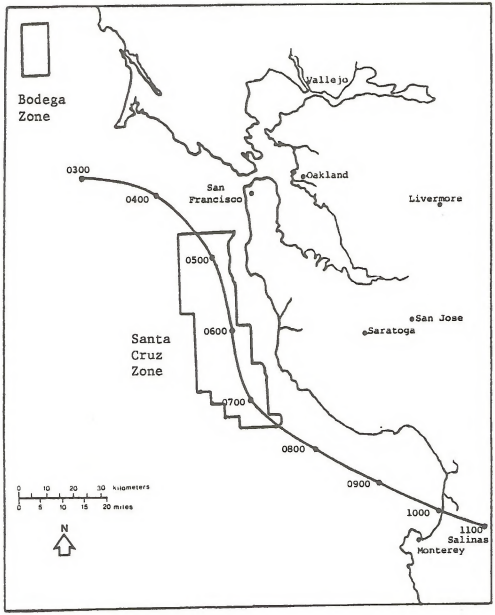
[Numbers along trajectory - e.g. 0500 - refer to time (PST) of day]

Figure IV-14. SAN FRANCISCO BAY AREA PHOTOCHEMICAL MODELING TRAJECTORY #6 FOR AUGUST 5, 1978 WITH 20 pphm O_3 MEASURED AT SARATOGA AT 1500 HOURS



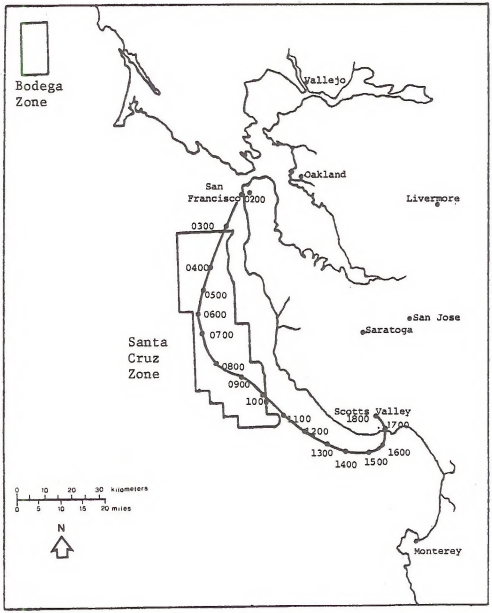
[Numbers along trajectory - e.g. 0500 - refer to time (PST) of day]

Figure IV-15. SAN FRANCISCO BAY AREA PHOTOCHEMICAL MODELING TRAJECTORY #2 FOR JULY 26, 1973 WITH 14 pphm O_3 MEASURED AT LIVERMORE AT 1500 HOURS



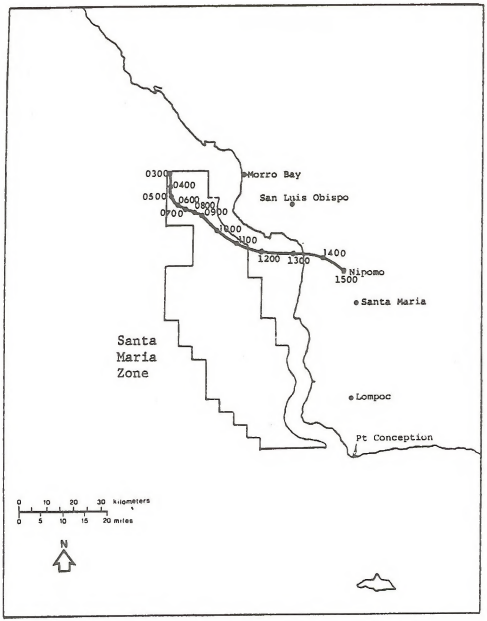
[Numbers along trajectory - e.g. 0500 - refer to time (PST) of day]

Figure IV-16. SALINAS PHOTOCHEMICAL MODELING TRAJECTORY FOR AUGUST 5, 1978, WITH 3 pphm O_3 MEASURED AT 1100 HOURS



[Numbers along trajectory - e.g. 0500 - refer to time (PST) of day]

Figure IV-17. SCOTTS VALLEY PHOTOCHEMICAL MODELING TRAJECTORY FOR SEPTEMBER 9, 1976, WITH 21 pphm O_3 MEASURED AT 1800 HOURS



[Numbers along trajectory - e.g. 0500 - refer to time(PST) of day]

Figure IV-18. NIPOMO PHOTOCHEMICAL MODELING TRAJECTORY FOR SEPTEMBER 29, 1978, WITH 14 pphm O_3 MEASURED AT 1500 HOURS

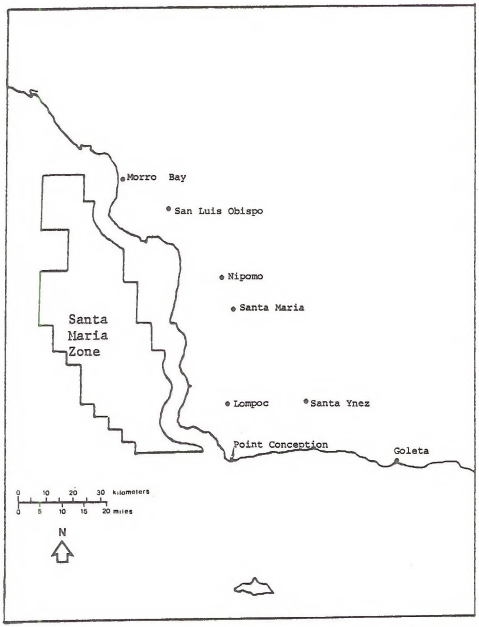
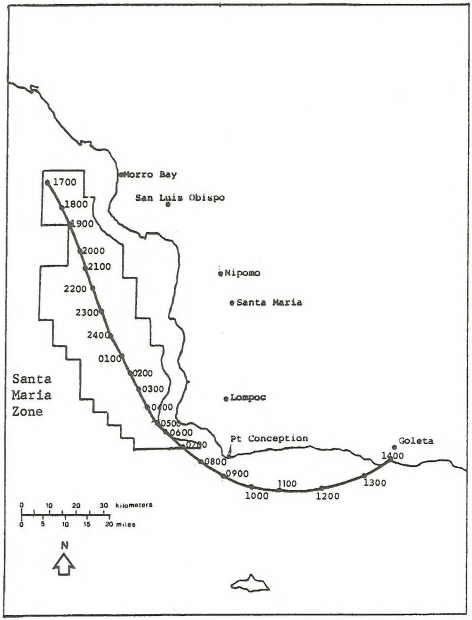
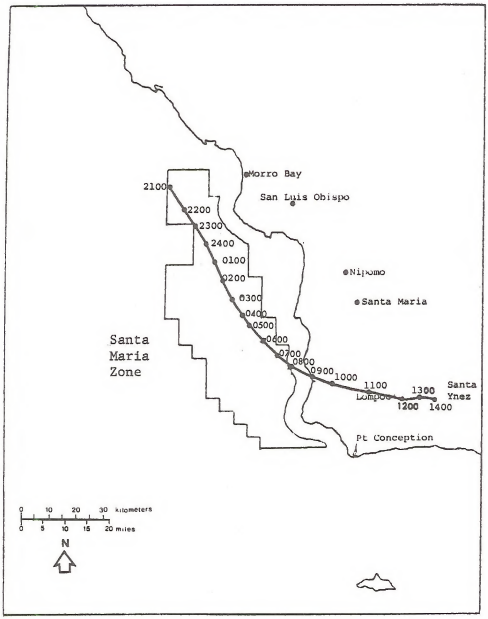


Figure IV-19. ONSHORE AREA ADJACENT TO THE SANTA MARIA ZONE



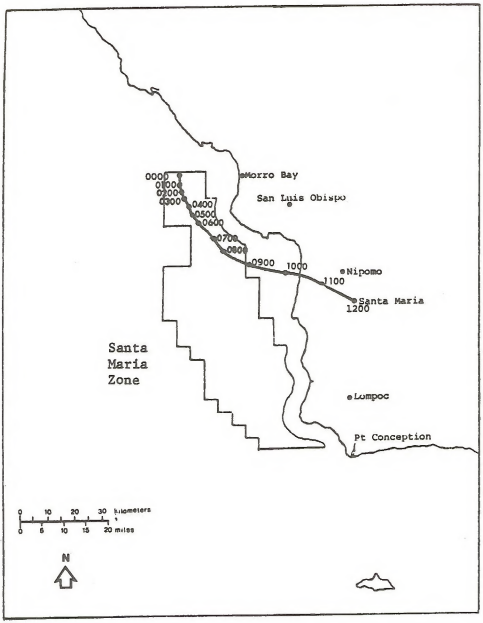
[Numbers along trajectory - e.g. 0500 - refer to time (PST) of day]

Figure IV-20. GOLETA PHOTOCHEMICAL MODELING TRAJECTORY FOR JUNE 20, 1976, WITH 3 pphm O_3 MEASURED AT 1400 HOURS



[Numbers along trajectory - e.g. 0500 - refer to time (PST) of day]

Figure IV-21. SANTA YNEZ PHOTOCHEMICAL MODELING TRAJECTORY FOR JUNE 5, 1977, WITH 13 pph, O_3 MEASURED AT 1400 HOURS



[Numbers along trajectory - e.g. 0500 - refer to time (PST) of day]

Figure TV-22. SANTA MARIA PHOTOCHEMICAL MODELING TRAJECTORY FOR JULY 30, 1977, WITH 12 pphm O_3 MEASURED AT 1200 HOURS

c. Frequency of Occurrence of Adverse Meteorological Conditions

Worst case meteorology occurs almost exclusively during July through October. High ambient ozone which is sometimes present offshore during these months may stimulate reaction of OCS emissions during the optimal morning hours of transport to shore. The significance of initial pollutant loading, however, has not been fully demonstrated. In any case, no data have been collected to specify the frequency of high ozone offshore in the study area.

The significance of meteorological conditions in affecting ozone from OCS emissions is only partially understood. Important parameters for ozone production seem to be the presence of an inversion layer offshore coupled with low wind speeds and flow onshore. These conditions are met most frequently during July through October. The analysis of offshore inversions in Section IV.A.2.c shows that the presence of reduced visibility is an acceptable surrogate for the presence of an inversion layer. Using these substitution and joint frequency tabulations of offshore winds compiled by the U.S. Navy (1976a and 1976b), joint frequencies for meteorological parameters were tabulated and are presented in Table IV-9. From these data it can be determined that the joint conditions are met at most during nine days each summer in three areas for which data are available. (This computation uses the highest frequencies in the table and assumes that the condition applies for one half of each day: [0.018 surface inversion frequency + 0.02 elevated inversion frequency] x 1/0.5 per frequency x 123 summer days = 9 days, using Point Arena data for wind speeds up to 10 knots.)

Assumption of the most frequently occurring conditions presented in Table IV-9 (presence of either a surface or elevated inversion and winds from the northwest, west or southeast with wind speeds of 10 knots or less) could result in some OCS-to-onshore trajectories with resultant ozone increments less than cases simulated in this study (i.e., ozone increments of 0.01 ppm or more for emissions from normal operations; meteorological conditions associated with these increments are herein called "adverse"). The more restrictive meteorological conditions tabulated in Table IV-9 would occur less frequently. For example, trajectories involving a surface inversion occur on, at most, four days each summer in the OCS Lease Sale No. 53 areas covered in Table IV-9. Trajectories with wind speeds of up to three knots occur on at most two days; and trajectories meeting both conditions occur on at most one day each summer. Most onshore trajectories from OCS areas would begin with air off the Pacific Ocean which would initially contain minimal amounts of air pollutants. Such trajectories, even under adverse meteorological conditions, would result in non-OCS onshore ozone levels significantly below air quality standards. Therefore, the multiple, simultaneous occurrence of conditions that could lead to violation of ozone air quality standards from unmitigated Lease Sale No. 53 emissions would be very small, probably less than once per year. A more precise quantification cannot be made without the compilation of additional field data in the offshore and nearshore environments.

B. Air Quality

1. Introduction

This summary of the air quality of the offshore and coastal areas between North latitudes 34° and 42° stresses the aspects which have a bearing on the assessment of air quality effects of future development of offshore petroleum

assessment of air quality effects of future development of offshore petroleum resources. The principal considerations are ambient hydrocarbon and oxidant (especially nitrogen dioxide and ozone) levels necessary for modeling and baseline levels of all other pollutants for which there are air quality standards and regulations. Table III-1 summarizes California and national ambient air quality standards. Extensive tabulations of air quality data are not reproduced in this report. References are cited which list additional data. Data were requested from the Air Pollution Control Districts and from the California Air Resources Board at the start of the study. The principal data summaries made available, and which serve as the basis of this section, are contained in the appropriate air quality maintenance planning documents.

Air quality at sensitive receptor sites is a function of pollutant emissions and atmospheric transport. Atmospheric transport can be considered as a bridge connecting emissions sources with ambient air quality at receptor locations downwind.

2. Summary of Air Quality Measurements and Compliance with Air Quality Standards

a. North Coast Air Basin

Refer to Figure III-3 for the location of the North Coast Air Basin. The pollutants of concern are suspended particulate matter (TSP), lead, and hydrogen sulfide (H_2S). Principal sources of TSP include combustion, wood processing, and vehicular traffic on dusty roads. (Offshore petroleum development is a minor source of TSP.) Vehicles are the source of lead, and geothermal development is the main source of hydrogen sulfide. Data collection for other pollutants has been limited. The measurements cited in the subsections below are taken from California North Coast Air Basin Air Pollution Control Council (1977).

i. Carbon Monoxide

Recorded concentrations of carbon monoxide (CO) are well below all CO ambient air quality standards. The basin wide CO emissions are projected to decrease slightly by 1995. Based on the limited air quality data and projected decrease in CO emissions, it appears likely that CO concentrations will not violate the state and national ambient air quality standards through 1995.

The California one-hour CO air quality standard is 40 parts per million (ppm). Average daily maximum-hour measured CO in Eureka has been about 2.4 ppm in recent years. The yearly maximum-hour reading has been 12 to 15 ppm.

ii. Nitrogen Oxides

Recorded concentrations of nitrogen dioxide (NO_2) are presently well below the state and national ambient air quality standards. Basin-wide nitrogen oxide (NO_x) emissions are projected to increase slightly by 1980. They are then projected to decrease slightly by 1985 through vehicular compliance with the state emission limitations. Thereafter, the emissions are projected to increase by about ten percent through 1995. Based on the limited ambient air quality data, it appears unlikely that the NO_2 concentrations will violate the state and national ambient air quality standards through 1995.

Table IV-9. JOINT FREQUENCIES FOR WORST CASE ONSHORE FLOW[1]

Onshore Reference Point	Month	Surface Inversion and Wind Speed Range: 0-3 Kts.	Surface Inversion and Wind Speed Range: 0-10 Kts.	Elevated Inversion and Wind Speed Range: 0-3 Kts.	Elevated Inversion and Wind Speed Range: 0-10 Kts.
Eureka	July	0.3	0.9	0.2	0.8
	Aug.	0.6	1.1	0.4	1.3
	Sept.	0.7	1.2	0.1	0.5
	Oct.	0.4	1.5	0.2	0.9
Pt. Arena	July	0.1	1.1	0.3	1.3
	Aug.	0.4	1.5	0.5	2.2
	Sept.	0.5	2.5	0.6	2.2
	Oct.	0.7	2.1	0.7	2.2
San Francisco	July	0.1	1.0	0.2	2.0
	Aug.	0.3	0.9	0.3	0.8
	Sept.	0.3	1.8	0.1	1.6
	Oct.	0.3	2.1	0.2	1.9

1. Percentage of time with flow from the northwest, west, or southwest.

Data source: (U.S. Navy, 1976a and 1976b)

The California one-hour NO_2 air quality standard is 0.25 ppm. Monitoring in Eureka during 1972-1973 resulted in an average of 0.017 ppm, an average daily maximum hour of 0.03 ppm, and two year maximum hour of 0.11 ppm. Mobile monitoring during shorter periods during 1974 in Cloverdale, Ukiah, and Willits resulted in similar measured concentrations.

iii. Sulfur Oxides and Hydrogen Sulfide

Recorded concentrations of sulfur dioxide (SO_2) are presently well below all ambient air quality standards. The basin-wide SO_2 emissions are projected to increase by about 76 percent by 1995. Nonetheless, the probability of SO_2 concentrations exceeding the standards through 1995 are low.

The California SO_2 standard is 0.05 ppm during a 24-hour averaging period. Measurements in Eureka have been less than 0.01 ppm.

Hydrogen sulfide (H_2S) is a significant problem in the Known Geothermal Resource Area (KGRA) in Sonoma and Lake Counties. Most of the recent ambient H_2S increases have been in Lake County, which is a separate air basin. H_2S is not a problem on the coast near proposed OCS development.

iv. Hydrocarbons

There have been selected measurements of hydrocarbons by the California Air Resources Board mobile air monitoring van. The average of the daily maximum hourly values during monitoring has ranged from 0.2 ppm at Cloverdale to 1 ppm at Willits. The higher hours monitored exceed the 6 to 9 a.m. federal air quality standard (0.24 ppm). Basin-wide hydrocarbon emissions are expected to increase by about 11 percent through 1995.

v. Ozone

The one-hour state standard is 0.10 ppm and the federal standard is 0.12 ppm. (The state standard may not be equalled and the federal standard may not be exceeded more than once each year.)

Violations of the national ambient air quality standard for ozone and of the state standard for oxidants have not been recorded. Highest and second-highest concentrations at Eureka were 0.06 ppm in 1973 and 0.05 ppm in 1972. Ozone data recorded in Ukiah during the summer of 1978 show a high one-hour average of 0.09 ppm. Very limited available air quality data make it impossible to project future oxidant levels.

vi. Suspended Particulate Matter

Total Suspended Particulate matter (TSP) is one of the most difficult pollution problems in the southern half of the North Coast Air Basin. Ambient concentrations substantially exceed both the state and national ambient air quality standards, and basin-wide emissions are projected to increase steadily over the next 20 years.

TSP annual geometric means have ranged between 38 and 62 $\mu g/m^3$ from 1971 through 1976. These values were below federal secondary and state standards of 60 micrograms per cubic meter ($\mu g/m^3$) until 1976. The federal primary

standard is 75 $\mu g/m^3$. TSP concentrations in Eureka have frequently exceeded the state 24-hour standard of 100 $\mu g/m^3$.

b. San Francisco Bay Area Air Basin

Some air quality standards are exceeded in the San Francisco Bay area. These include standards for ozone and oxidants, the eight-hour federal CO standard, the state one-hour NO_2 standard, and annual TSP standards. Data in this air quality summary are taken from 1979 Bay Area Air Quality Plan (Association of Bay Area Governments, et al., 1979). More detailed tabulations are available from the Bay Area Air Quality Management District. Refer to Figure III-3 for the location of the air basin comprising the San Francisco Bay area.

i. Carbon Monoxide

Over 90 percent of CO is emitted by vehicles in a complex pattern corresponding to highway networks in the Bay Area. The federal one-hour CO standard has not been exceeded in the Bay Area during the 1970s, according to monitoring data collected by the Bay Area Air Quality Management District. The federal eight-hour standard of 9 ppm, however, has been frequently exceeded in some areas. Figure IV-23 displays contours of days exceeding the federal standard. Over 80 percent of violations occur from November through January. On a daily basis, more than 90 percent of the violations occur between 4 p.m. and 2 a.m. The CO problem is very localized, and concentrations in excess of the one-hour standard have been measured at such sites as San Francisco International Airport. Emissions have decreased slowly in recent years, but measured ambient CO levels have decreased more slowly.

ii. Nitrogen Oxides

Ambient NO_2 concentrations in the Bay Area Air Basin have never exceeded the federal annual NO_2 air quality standard of 0.05 ppm. Figure IV-24 displays contours of annual average NO_2 concentrations. The one-hour state standard of 0.25 ppm has been exceeded.

NO_2 is an oxidation product of nitric oxide (NO). The latter is a primary pollutant. From 1968 to 1975, the annual NO average concentration at San Francisco has decreased more than 40 percent, while at San Jose it has increased about 20 percent. The Santa Clara Valley has shifted from being a receptor of nitrogen oxides (NO_x) to being a source.

iii. Sulfur Oxides and Hydrogen Sulfide

None of the sulfur dioxide standards are exceeded or likely to be exceeded in the Bay Area through 1995. The contour map of annual SO_2 values for 1975 (Figure IV-25) shows a narrow band exceeding 0.003 ppm (3 ppb) centered on the shores of Contra Costa County with extensions to the International Airport and into the Delta. Most of the Bay Area experiences values less than ten percent of the federal standard (0.03 ppm). The area of highest values corresponds approximately with the zone of major industry in the basin. Seasonal climatic factors also have a significant effect upon the annual SO_2 values.

The state one-hour standard (0.5 ppm) was exceeded at Crockett in 1975, a base year for air quality maintenance planning. The Bay Area Air Quality Management District has a three-minute regulation which is exceeded often.

Hydrogen sulfide is not an ambient air quality problem in the Bay Area. The state 24-hour sulfates standard (25 $\mu g/m^3$) is not exceeded in the air basin.

iv. Hydrocarbons

Too few hydrocarbon (HC) measurements have been recorded in the Bay Area to construct contours. Concentrations of HC should correspond well with HC emissions. The principal emissions sources are light duty automobiles and evaporation of organic solvents. Highest concentrations should correspond approximately with major traffic corridors, while other high zones should be associated with major commercial and some industrial areas (such as refineries near Richmond).

The federal standard of 0.24 ppm during 6-9 a.m. is not a health standard, but serves as a control on ozone formation. High measurements of hydrocarbons in the Bay Area Air Basin range roughly between 4 and 10 ppm. The federal standard is for hydrocarbons with the methane fraction removed (called non-methane hydrocarbons).

v. Ozone

Ozone levels have generally declined during the past decade; but there are large daily and annual weather-induced fluctuations in levels. Figures IV-26a and IV-26b display contours of mean number of days during 1970-1975 for which oxidants (ozone and other oxidizing compounds) in the Bay Area exceeded the former federal one hour average standard of 0.08 ppm.

It is not possible to make precise predictions of ozone trends, since weather plays a significant role in determining the number of days annually exceeding the standards. The District has developed a trend technique to damp out primary weather factors (temperature and inversion height) and compare oxidant levels only for days when conditions favor high ozone levels. Figure IV-27 graphs results of this study. Clearly, some fluctuation which results from other weather factors is evident in the declining mean oxidants trend line. The two long-established monitoring stations with averages exceeding the federal standard are San Jose and Livermore. Another feature displayed in the trend graph is the southeastward migration of highest values over the years.

vi. Total Suspended Particulate Matter

Contours of annual geometric means of total suspended particulates (TSP) show a pattern of low values near the coast, increasing with distance inland (Figure IV-28). In 1975 the Santa Clara and Livermore Valley areas exceeded the state standard (60 $\mu g/m^3$). The Livermore Valley also exceeded the federal standard (75 $\mu g/m^3$).

vii. Offshore Data

The only offshore area pertinent to this study with available air quality data lies between San Francisco and Monterey. The U.S. Navy Postgraduate School at Monterey conducted offshore data collection under contract to the California Air Resources Board during 1978.

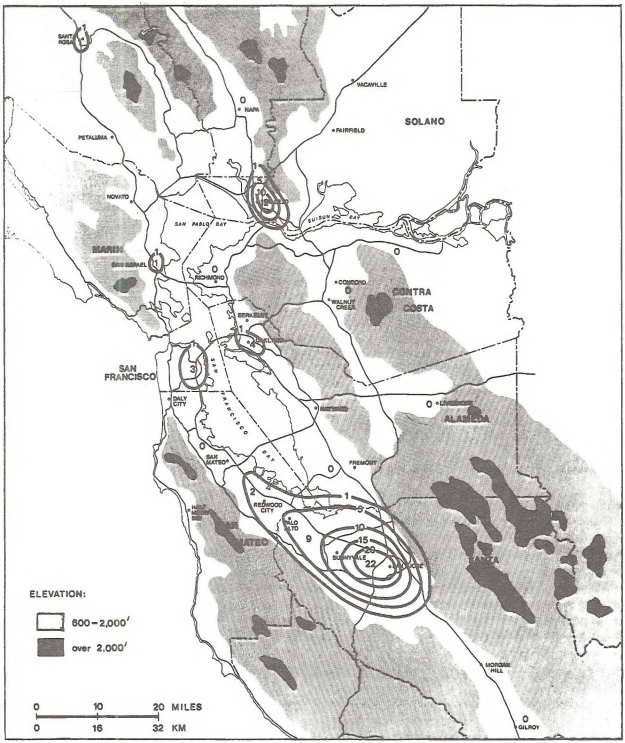


Figure IV-23. SAN FRANCISCO 1975 ANNUAL NUMBER OF DAYS WITH CARBON MONOXIDE EXCEEDING FEDERAL STANDARD (9 ppm FOR 8 HOURS)

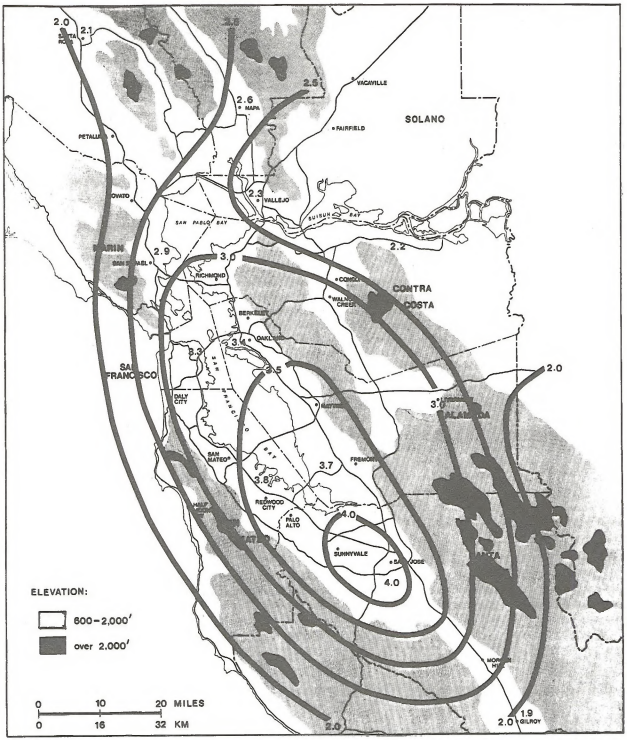


Figure IV-24. SAN FRANCISCO 1975 ANNUAL AVERAGE NITROGEN DIOXIDE VALUES IN PARTS PER HUNDRED MILLION (pphm) (FEDERAL STANDARD IS 5.0 pphm)

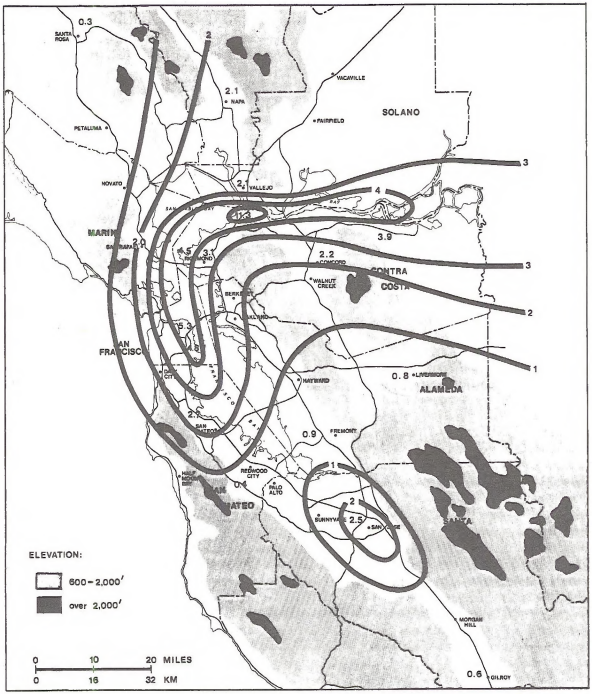


Figure IV-25. SAN FRANCISCO 1975 ANNUAL AVERAGE SULFUR DIOXIDE VALUES IN PARTS PER BILLION (ppb) (FEDERAL STANDARD IS 30 ppb)

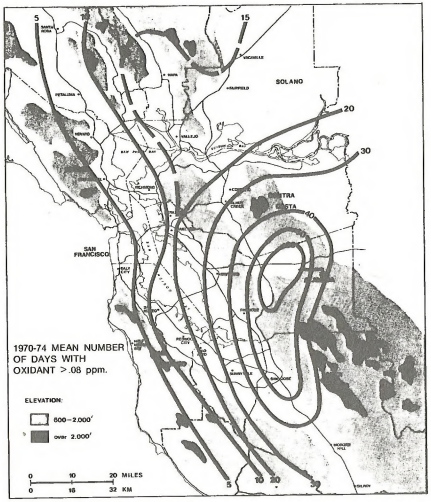


Figure IV-26a. SAN FRANCISCO 1970-74 MEAN NUMBER OF DAYS WITH OXIDANT >.08 ppm

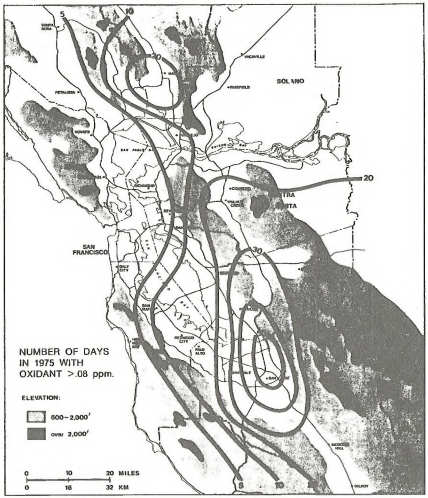


Figure IV-26b. SAN FRANCISCO 1975 NUMBER OF DAYS WITH OXIDANT >.08 ppm

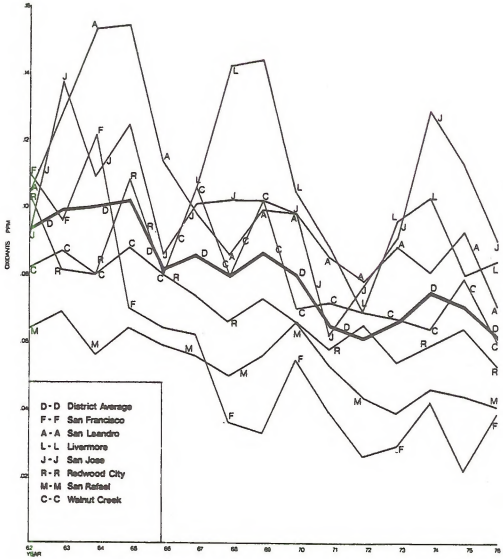


Figure IV-27. TREND OF AVERAGE HIGH-HOUR OXIDANT CONCENTRATIONS FOR DAYS WITH COMPARABLE TEMPERATURE & INVERSION CONDITIONS (APRIL THROUGH OCTOBER PHOTOCHEMICAL OXIDANT SEASONS 1962-1976 IN SAN FRANCISCO)

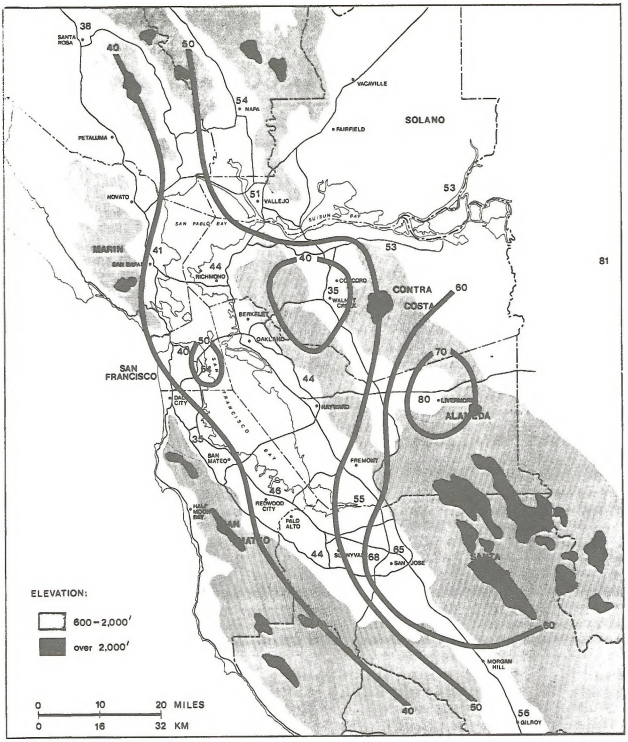


Figure IV-28. SAN FRANCISCO 1975 ANNUAL GEOMETRIC MEANS OF TOTAL SUSPENDED PARTICULATE IN $\mu g/m^3$ (FEDERAL PRIMARY STANDARD IS 75 $\mu g/m^3$, STATE STANDARD IS 60 $\mu g/m^3$)

The R/V Arcana steamed off San Francisco during July 31 through August 17, 1978. This was a period of anticipated high ozone in the Bay Area. Preliminary data reduction (Bennett, 1979) shows a maximum one-hour ozone level of 0.05 ppm. Maximal values for other pollutants are nitric oxide - 0.04 ppm; nitrogen dioxide - 0.04 ppm; carbon monoxide - 0.5 ppm; total hydrocarbons - 1.8 ppm; and non-methane hydrocarbons - 0.3 ppm.

c. North Central Coast Air Basin

Refer to Figure III-3 for location of the North Central Coast Air Basin. The Air Basin is a federal non-attainment area for ozone. The California 24-hour average particulate matter air quality standard is also exceeded.

Data is this section are taken from the Air Quality Plan for the Monterey Bay Region (Assoc. of Monterey Bay Area Governments, et al., 1978) and from California Air Quality Data (CARB, 1974-1979).

i. Carbon Monoxide, Nitrogen Dioxide, and Sulfur Dioxide

Carbon monoxide, nitrogen dioxide, and sulfur dioxide data recorded at monitoring stations meet all the air quality standards.

ii. Hydrocarbons

The 6-9 a.m. federal hydrocarbon air quality standard has been exceeded in the air basin. Maximum readings for hydrocarbons have been about 4 ppm in recent years.

iii. Ozone

The federal ozone standard was exceeded in 1976 and 1977, but not in 1974 and 1975. Table IV-10 displays highest and second highest oxidant concentrations during 1973 through 1977.

Highest ozone levels recorded in the air basin have been attributed to ozone transported from outside. Air quality maintenance planning is based on an air basin one-hour average level of 0.14 ppm, while the federal standard is 0.12 ppm. The highest historical ozone level was measured at Scotts Valley in 1976 (0.21 ppm). The annual highest one-hour average concentrations recorded at the several stations during the 1970s have ranged between 0.05 and 0.21 ppm, with most values falling in the range 0.10 to 0.14 ppm.

iv. Particulate Matter

Particulate matter levels near the coast have been below the state 24-hour average air quality standard. The standard is exceeded inland, principally because of greater wind-blown dust.

d. South Central Coast Air Basin

Refer to Figure III-3 for location of the South Central Coast Air Basin. The two coastal counties of interest to this study are San Luis Obispo and Santa Barbara.

Various subsections of the air basin are in nonattainment for one or more air pollutants. Carbon monoxide is in nonattainment on the south coast of Santa Barbara County. Ozone is in nonattainment throughout Santa Barbara County. San Luis Obispo County to the north, and the western part of Santa Barbara County are in nonattainment of the primary particulate standard. Data in this section are taken from the San Luis Obispo County and Santa Barbara County Air Quality Attainment Plans and from the California Air Resources Board SIP-78 Working Document, Chapter 17.

i. Carbon Monoxide

The carbon monoxide standard has not been exceeded in San Luis Obispo County since 1974. The second highest eight-hour average CO level in 1975, measured in San Luis Obispo, was within 1 ppm of the federal air quality standard (9 ppm). Since then, levels have decreased as newer automobiles, with improved pollution control devices, have replaced older ones. By 1978, the second highest eight-hour average had dropped to 44 percent of the federal standard.

In Santa Barbara County, the one-hour average federal standard (35 ppm) has been met, but the eight-hour standard and the state 12-hour standard (10 ppm) have been exceeded at the State Street monitoring site in the city of Santa Barbara. The sources of CO appear to be near the monitoring site.

ii. Nitrogen Oxides

Nitrogen dioxide (NO_2) is only measured in the City of San Luis Obispo in that county. The second highest NO_2 one-hour average concentration has been 60 percent, or less, of the state standard (0.25 ppm) during recent years. This standard is also not exceeded elsewhere in the county. The annual average value for Santa Barbara during 1972 through 1975 was 80 percent of the standard.

iii. Sulfur Oxides and Hydrogen Sulfide

There have been no violations of state or federal SO_2 standards in recent years. Highest SO_2 concentrations have been measured at Nipomo in San Luis Obispo County. The 24-hour average value in 1977 was 50 percent of the SO_2 value in the state standard (0.05 ppm; to exceed the SO_2 standard there must be concurrent violation of the state oxidant or particulate matter standard, as well). One-hour averages in 1977 have been, at most, 20 percent of the state standard (0.50 ppm).

Measurements of 24-hour average sulfates in Paso Robles (11.4 $\mu g/m^3$) and Santa Barbara (16.5 $\mu g/m^3$) during 1976 were below the state standard (25 $\mu g/m^3$). These are the only monitoring sites for sulfates in the air basin. There is no hydrogen sulfide problem in the air basin.

iv. Hydrocarbons

The 6-9 a.m. federal hydrocarbon standard (0.24 ppm corrected for methane) is regularly exceeded at the monitoring stations in San Luis Obispo and Santa Barbara. Typical highest total hydrocarbon values are about 5 ppm. Violation of this standard indicates a potential ozone problem.

v. Ozone

The second highest one-hour average ozone measurements in Paso Robles have been within 0.01 ppm of the federal ozone standard (0.12 ppm) during 1976 and

Table IV-10. HIGHEST AND SECOND-HIGHEST OXIDANT CONCENTRATIONS, NORTH CENTRAL COAST AIR BASIN - ONE-HOUR AVERAGE (PARTS PER MILLION)

LOCATION	1973	1974	1975	1976	1977
Scotts Valley	*	*	*	0.21/0.16	0.10/0.19
Aptos	*	*	*	0.13/0.12	0.12/0.10
Santa Cruz	0.10/0.09	0.09/0.09	0.08/0.07	*	*
Hollister	0.11/0.10	0.11/0.10	0.11/0.11	0.15/0.14	0.14/0.14
Salinas	0.12/0.10	0.10/0.09	0.07/0.06	0.11/0.11	0.08/0.08
Monterey	0.12/0.11	0.11/0.09	0.07/0.06	0.07/0.07	0.07/0.06
Gonzales	0.13/0.12	0.10/0.09	0.10/0.10	0.08/0.08**	0.09/0.09
Carmel Valley	0.10/0.09**	0.10/0.09**	0.09/0.08	0.05/0.05**	*

Notes:
* No data available
** Full year's data not available

Standards: State 1-hour average = 0.10 ppm
National 1-hour average = 0.12 ppm

Source: Association of Monterey Bay Area Governments, et al. (1978).

1978. San Luis Obispo and Nipomo have had corresponding values within 0.02 ppm since 1976. The state one-hour standard (0.10 ppm) has been violated in all three cities within the same four year period.

Second highest annual one-hour average zone levels in the city of Santa Barbara have exceeded the federal standard every year since data have been collected. The peak-hour ozone level in 1977 was 0.19 ppm. A second highest ozone value of 0.22 ppm was measured at the Goleta and Cathedral Oaks monitoring stations in 1975 and 1976. Very limited measurements at the San Ynez Airport gave a second-highest value of 0.12 ppm in November, 1977. Second highest ozone values in 1976 and 1977 at Santa Maria were 0.12 and 0.11 ppm, respectively.

vi. Total Suspended Particulate Matter

The state 24-hour average particulate standard is exceeded at monitoring stations in San Luis Obispo County. Second highest values during 1976 through 1978 ranged from 90 $\mu g/m^3$ (San Luis Obispo in 1978) through 177 $\mu g/m^3$ (Paso Robles in 1976).

Santa Maria experiences high readings. The federal primary standard (260 $\mu g/m^3$) was exceeded in 1972 and 1973 (second highest values of 336 and 320 $\mu g/m^3$, respectively). The secondary standard (150 $\mu g/m^3$) is exceeded over larger areas of northern Santa Barbara County. The federal secondary and state annual geometric mean (60 $\mu g/m^3$) have been exceeded in Paso Robles, Santa Maria, Lompoc, and Santa Barbara in recent years. The federal primary annual geometric mean (75 $\mu g/m^3$) has been exceeded in Santa Maria and Lompoc during one or more years in 1972.

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V. AIR EMISSIONS INVENTORY

A. Introduction

The following air emission inventory is based largely on studies prepared by the United States Geologic Survey (USGS, 1978) and the Bureau of Land Management (BLM, 1979b; BLM, 1979c). The USGS study predicts the expected production levels in each of the five proposed lease tract zones for three different resource estimates. The study also predicts the number of wells expected to be drilled and the number and types of platforms which would be installed for each resource estimate. The resource estimates are discussed in detail in Section II.B. The BLM study provides four transportation scenarios, specifying the mode of transportation, the final destination of the oil and/or gas produced, and the characteristics of the vessels and pipelines which would be used. The transportation scenarios are described Section V.B.2.

The emission inventory separately addresses emissions associated with: (1) offshore activities, (2) oil and gas transportation, (3) onshore operations. First, a general description of operations and major types of emissions is given, and then emissions associated with each proposed zone are described.

To facilitate the lay reader's understanding of this material only daily, hourly and annual summary tables are presented in the text. Support data can be found in Appendix A for those who wish to evaluate the technical assumptions made in preparing the emission inventory.

It should be noted that although great care has been taken to ensure that this emission inventory is as accurate as possible, many uncertainties do exist. As stated earlier, much of the air emission inventory is based on the three resource estimates prepared by the USGS. As evidenced by previous lease sales, the actual quantity of resources that may be recovered could vary significantly from early estimates. In addition, differences in the operating techniques among oil companies may affect the actual emissions that would occur. Finally, the rules and regulations which will govern future OCS activities still are not clear. The U.S. Department of the Interior (DOI) is currently developing statutes which will place limitations on air pollutant emissions generated by OCS operations. Until the DOI regulations are final, however, these limitations are only a matter for speculation. Therefore, in the absence of the DOI rules, this study has estimated emissions based on the best available engineering operational emission factors.

This analysis is intended to estimate conservatively the relative magnitudes, types and distributions of emissions that may occur from proposed Lease Sale No. 53 activity; it is not intended to, and cannot, provide an exact representation of the expected emissions. After the proposed tracts are leased and the quantity of resources and scope of planned development are more accurately known, a more precise estimate of the emissions can be prepared.

B. Offshore Emissions

1. Platform and Supportive Activity

a. Exploration

OCS activity generally begins with a marine geophysical survey of the area being considered, to determine the potential for oil and/or gas development.

Since the potential for development in Lease Sale No. 53 has already been established, it is assumed that geophysical surveys of some kind have been performed.

With the potential for oil and/or gas established, exploratory drilling would begin in each zone to determine if sufficient quantities of oil and/or gas exist to merit a development effort. If sufficient quantities are found, delineation drilling would begin and the optimum locations for platform installations and development wells would be sought. Delineation drilling would begin shortly after exploratory drilling, continue concurrently, and end a short time after the conclusion of exploratory drilling.

The total number of exploratory and delineation wells drilled would depend upon the resources found in each zone. The United States Geological Survey (USGS) has made estimates of the numbers of exploratory and delineation wells expected to be drilled for the low, high and mean resource estimates. The low resource estimate carries a 95 percent probability of being realized, while the high estimate carries a 5 percent probability. These values are presented in Tables V-1 and V-2.

Total emissions during the exploration and delineation phase of OCS activity would be relatively small when compared with emissions of the development or production phases. They would primarily be pollutants associated with the combustion of fuel in internal combustion engines supplying power for the drilling rigs and support vessels. Of the pollutants which would be emitted, nitrogen oxides (NO_x) and carbon monoxide (CO) make up the largest portion.

i. Construction and Installation

There are a number of types of drilling rigs that may be used for exploratory drilling. These include jack up, submersible and semi-submersible rigs, and drill ships. The actual type of rig chosen would depend on water depth, environmental criteria, type of sea bottom and other factors. For purposes of estimating emissions from exploratory drilling activities, it is assumed that mobile drilling rigs would be used for all exploratory and delineation wells. As these rigs would normally be fabricated onshore and towed to the area where drilling would occur, it is assumed that emissions associated with installing the drilling rig would be negligible.

ii. Power Generation

Emissions resulting from power generation for drilling and miscellaneous uses would be the only major stationary emissions during the exploratory phase of activity, and would comprise a large portion of the total emissions from all exploratory and delineation drilling activity.

The power for drilling would be supplied by electric motors. Electricity may be transmitted by a submarine cable from shore or generated by diesel-fired turbines or reciprocating engines installed on the rig itself, the latter being the most common method (Energy Resources Co., 1977). In estimating emissions from drilling power generation for this study, it was assumed that diesel-fired reciprocating engines would be used during exploratory and delineation drilling. Emission factors for these engines are presented in Table A-1 in Appendix A.

Table V-1. LOW, HIGH AND MEAN RESOURCE ESTIMATES OF LEASE SALE NO. 53 OIL AND GAS PRODUCTION[1]

Zone	Resource Estimate	Product[2]	Year 1986	1987	1988	1989	1990	1991	1995	2000	2005
Eel River	Low	Gas (MCFD)	13,200	24,700	21,100	18,100	15,300	13,200	6,800	3,300	1,400
	High	Gas (MCFD)	47,100	60,000	60,000	60,000	60,000	60,000	60,000	49,300	4,900
	Mean	Gas (MCFD)	28,200	50,100	50,100	49,900	49,900	49,900	22,700	8,500	3,300
Point Arena	Low	Gas (MCFD)	9,300	26,000	28,800	28,500	23,800	20,000	10,400	4,400	1,900
		Oil (BOD)	9,300	26,300	28,800	28,500	24,100	20,300	10,400	4,400	1,900
	High	Gas (MCFD)	13,300	38,300	72,400	75,400	70,300	58,000	27,500	10,800	3,800
		Oil (BOD)	12,900	36,400	68,700	71,600	66,700	55,000	26,100	10,200	3,600
	Mean	Gas (MCFD)	9,600	27,400	42,200	47,400	40,000	34,000	17,300	7,400	3,300
		Oil (BOD)	9,300	26,300	40,500	45,800	38,600	32,600	16,700	7,200	3,000
Bodega[3]	Low	Gas (MCFD)	1,100	2,000	1,900	1,700	1,600	1,500	1,100	700	500
		Oil (BOD)	1,100	2,000	1,900	1,700	1,600	1,500	1,100	700	500
	High	Gas (MCFD)	4,700	13,500	15,400	15,600	13,400	11,600	6,400	3,000	1,400
		Oil (BOD)	4,600	13,300	16,100	15,300	13,200	11,400	6,300	3,000	1,400
	Mean	Gas (MCFD)	3,000	7,500	6,600	5,800	5,100	4,600	2,800	1,400	800
		Oil (BOD)	3,200	7,900	6,900	6,100	5,400	4,800	2,900	1,500	800
Santa Cruz	Low	Gas (MCFD)	700	1,900	2,400	3,600	3,600	3,500	2,400	1,700	1,100
		Oil (BOD)	700	1,900	2,400	3,600	3,600	3,300	2,400	1,700	1,100
	High	Gas (MCFD)	7,600	29,300	57,600	78,200	84,500	77,200	42,800	20,500	9,800
		Oil (BOD)	7,400	28,700	56,400	76,600	82,800	75,700	42,000	20,100	9,600
	Mean	Gas (MCFD)	1,600	10,100	21,000	30,500	35,600	33,100	20,000	10,700	5,700
		Oil (BOD)	1,500	9,600	19,900	28,900	33,800	31,400	19,000	10,100	5,400
Santa Maria	Low	Gas (MCFD)	2,800	9,700	13,400	18,300	22,700	21,500	14,600	8,800	5,400
		Oil (BOD)	2,700	9,300	12,900	17,600	21,800	20,700	14,000	8,500	5,200
	High	Gas (MCFD)	12,500	60,200	130,900	189,900	221,100	232,400	138,800	59,700	25,100
		Oil (BOD)	12,100	58,400	127,100	184,400	214,700	225,600	134,800	58,000	24,400
	Mean	Gas (MCFD)	8,800	38,100	72,600	96,200	114,000	120,700	69,600	33,400	16,000
		Oil (BOD)	8,400	36,500	69,600	92,200	109,300	115,100	66,700	32,000	15,300

1. Source: USGS supplied resource estimate (1979). To find annual production levels, multiply daily total by 365.
2. MCFD refers to thousand cubic feet of gas produced per day. BOD refers to barrels of oil produced per day.
3. Gas in the Bodega zone would be reinjected.

Table V-2. ESTIMATED NUMBER OF WELLS TO BE DRILLED DURING LEASE SALE NO. 53 OCS ACTIVITY[1]

Zone	Year	Low Resource Estimate			High Resource Estimate			Mean Resource Estimate		
		Exploratory	Delineation	Development	Exploratory	Delineation	Development	Exploratory	Delineation	Development
EEL RIVER	1981	1	--	--	2	--	--	1	--	--
	1982	1	1	--	3	5	--	2	3	--
	1983	1	2	--	1	5	--	1	3	--
	1984	--	2	--	--	4	--	--	1	--
	1985	--	--	--	--	--	--	--	--	--
	1986	--	--	4	--	--	6	--	--	6
	1987	--	--	4	--	--	6	--	--	12
	1988	--	--	--	--	--	6	--	--	--
	1989	--	--	--	--	--	6	--	--	--
POINT ARENA	1981	1	--	--	2	--	--	1	--	--
	1982	2	2	--	3	5	--	2	3	--
	1983	1	2	--	1	5	--	2	4	--
	1984	--	1	--	--	3	--	--	2	--
	1985	--	--	--	--	--	--	--	--	--
	1986	--	--	14	--	--	14	--	--	14
	1987	--	--	28	--	--	28	--	--	28
	1988	--	--	10	--	--	42	--	--	28
	1989	--	--	6	--	--	16	--	--	17
	1990	--	--	--	--	--	8	--	--	--
BODEGA	1981	1	--	--	1	--	--	1	1	--
	1982	1	1	--	2	2	--	1	2	--
	1983	--	2	--	--	5	--	--	1	--
	1984	--	--	--	--	4	--	--	--	--
	1985	--	--	--	--	--	--	--	--	--
	1986	--	--	8	--	--	10	--	--	10
	1987	--	--	8	--	--	20	--	--	16
	1988	--	--	--	--	--	10	--	--	--
	1989	--	--	--	--	--	3	--	--	--

Table V-2 (continued)

Zone	Year	Low Resource Estimate			High Resource Estimate			Mean Resource Estimate		
		Exploratory	Delineation	Development	Exploratory	Delineation	Development	Exploratory	Delineation	Development
SANTA CRUZ	1981	3	--	--	5	--	--	4	--	--
	1982	5	4	--	8	8	--	6	6	--
	1983	4	6	--	5	12	--	5	10	--
	1984	2	3	--	2	10	--	2	8	--
	1985	--	3	--	1	7	--	1	3	--
	1986	--	1	5	--	4	16	--	--	8
	1987	--	--	10	--	2	48	--	--	26
	1988	--	--	5	--	--	68	--	--	36
	1989	--	--	10	--	--	60	--	--	36
	1990	--	--	2	--	--	36	--	--	26
	1991	--	--	--	--	--	9	--	--	5
SANTA MARIA	1981	3	--	--	5	--	--	4	--	--
	1982	5	4	--	8	10	--	6	6	--
	1983	3	6	--	6	14	--	5	12	--
	1984	2	3	--	3	11	--	3	8	--
	1985	--	3	--	1	8	--	1	4	--
	1986	--	--	14	--	6	18	--	3	18
	1987	--	--	35	--	3	72	--	--	63
	1988	--	--	23	--	--	116	--	--	82
	1989	--	--	30	--	--	115	--	--	69
	1990	--	--	30	--	--	88	--	--	64
	1991	--	--	5	--	--	66	--	--	46
	1992	--	--	--	--	--	40	--	--	9
	1993	--	--	--	--	--	8	--	--	--

1. Source: USGS development scenario for Lease Sale No. 53 (1979).

2. Development wells include production wells and subsea completions.

The total power demand, and the consequent emissions, would depend upon the activity occurring at a given time. For example, the power usage when drilling at 5,000 feet would be greater than the demand when a new well is being started. To account for these variations in power usage, drilling scenarios based on well depth, drilling time and estimates of installed power and usage factors have been developed for wells in every zone. These scenarios, as well as other assumptions and methods used in calculating emissions from exploratory and delineation drilling power generation, are discussed further in Section V.D.1.

iii. Miscellaneous Sources

Power generation would be a continuous source of emissions on the drilling rigs. Other activities are expected to produce emissions intermittently and in lesser quantities. Examples of these are mud degassing and emissions from tests done on potential oil and/or gas wells. Normally, emissions from these activities would not be significant when compared to more continuous sources of pollutants.

iv. Support Activity

Considerable amounts of pollutants would be emitted from vessels supporting the drilling rigs. These would primarily be emissions from internal combustion engines powering the support boats. The main pollutants emitted would be nitrogen oxides (NO_x) and carbon monoxide (CO).

Support boats would be used to transport supplies and crews to and from the drilling rigs. Emissions from the support vessels would occur between the rig and the point of origin onshore. This point of origin would differ from zone to zone as would the distance traveled. Even though relatively high quantities of pollutants could be emitted by the supply and crew boats, the area over which the emissions would be dispersed must be considered. This consideration is necessary to obtain a perspective on the magnitude of emissions expected. The assumptions made and methods used in calculating emissions from support activities for exploratory and delineation drilling are discussed in detail in Section V.D.1, under Methodology and Assumptions.

b. Development Phase

When exploratory drilling has confirmed that sufficient quantities of oil and/or gas exist in a zone to justify production, development in that area would begin. The development phase would include the installation of platforms, pipelines and processing facilities, and the drilling of production wells.

A number of previous studies, e.g. AeroVironment (1977) and Office of Planning and Research (1976), have concentrated on the production phase of OCS activity in analyzing air quality impacts. The view is widely held that activities during this phase would be the main source of air pollutants. However, calculations done in the preparation of this study have indicated that development phase activities would also lead to the emission of large quantities of nitrogen oxide (NO_x), carbon monoxide (CO) and total suspended particulates (TSP).

Development would typically start shortly after the exploration phase, and end during or shortly after the peak production level in an area is reached.

The number of production wells drilled, type and number of platforms installed, and miles of pipeline laid would depend upon the amount of recoverable resources in a zone and, to some extent, the transportation and processing plans for the oil and/or gas after production. The USGS has provided development scenarios for each zone in Lease Sale No. 53 based on high, low and mean resource estimates and four different transportation scenarios. These estimates are presented in Tables V-1 through V-4.

i. Construction/Installation

The major sources of emissions during construction and installation would be internal combustion engines powering (1) vessels and equipment used in the installation of pipelines and platforms and (2) crew boats transporting personnel and supply boats delivering materials.

a) Platform Installation

The USGS has estimated that four different types of platforms would be installed and used in OCS operations within Lease Sale No. 53. The first is a production platform which can accommodate production of oil and/or gas. This type may be built either as a conventional or deep water (1,200 feet or greater) platform. The second type is a floating production system. This is described as a floating vessel (perhaps a converted tanker) attached to a mooring system where production and processing of oil and/or gas would occur. Physically similar to the floating production system is the offshore storage and treatment facility. The facility would be a floating vessel, used solely for processing gas and oil, and for loading tankers when applicable. The final platform considered by the USGS would only be needed in the Santa Maria zone. Termed an alternate gas processing platform, it would be a true fixed platform, used solely for gathering natural gas, processing it, and piping the gas to shore.

As stated previously, the major emission sources associated with the installation of platforms in each zone would be the vessels involved in the actual installation and the vessels used for support. The estimated numbers, types, and operational characteristics used in calculating the emissions from platform installation are discussed in detail in Section V.D.1.

b) Pipeline Installation

As in the case of platform installation, the major emission sources involved with pipeline installation would be the vessels involved in the installation operation and those vessels providing support. The daily emissions would be of the same magnitude as those occurring during platform installation. However, pipeline installation is not expected to occur over a long period of time. Thus, the annual emissions would be relatively small.

Two types of subsea pipelines would be laid. First, gathering lines would be needed to bring oil and gas from the wells to one or more central platforms for processing, tanker loading or subsequent transfer to shore. Then separate delivery lines would be required to transfer the gas or oil to shore. The total amount of pipeline laid in a given zone would depend upon the resource estimate and the expected transportation scenario. Table V-4 presents the number of pipeline expected to be laid for all zones, resource estimates, and transportation scenarios.

The methods and assumptions used in calculating emissions from pipeline installation are described in Section V.D.1.

ii. Power Generation

The major demand for power generation during development would be for well drilling. Combustion of fuel in the engines or turbines generating the required power would result in the emission of a significant amount of pollutants. The major pollutant emitted is expected to be nitrogen oxides (NO_x).

The required power scenarios and other assumptions used in calculating the emissions associated with development drilling are discussed in detail in Section V.D.1.

iii. Support Activities

It is expected that there would be a larger amount of support activity, and thus a larger quantity of emissions associated with the support vessels, during development than during the later production phase. These emissions would correspond to the larger demand for workers and supplies during the development phase. Emissions from development support activity may be quite high in some areas, due to the large distances the support vessels are assumed to travel. This distance would vary from zone to zone, as would the emissions associated with support activity. The actual distances used, frequency of trips made and other assumptions and methods used in estimating emissions from production support activity are discussed in greater detail in Section V.D.1.

c. Production Phase

Emissions from oil and gas production would come from a wide variety of sources. These would include the turbines and reciprocating engines used in power power generation, separators, heat treaters and dehydrators used in processing oil and gas, and pumps, compressors and other sources of fugitive evaporative emissions. In addition to emissions directly related to production and processing, there would be a significant amount of pollutants emitted by support vessels.

Pollutants from the production phase would be emitted steadily over the producing life of each zone. In contrast, emissions associated with the exploratory and development phases would occur for only a relatively brief period.

Another difference between emissions during the production phase and the exploratory and development phases is that most pollutants from production and processing are expected to be emitted from stationary sources, whereas, emissions associated with exploration and development would primarily be generated by mobile sources.

i. Power Generation

Power generated on offshore platforms would be required primarily for gas compression (for gas transmission, artificial gas lift or processing), oil pumping (to pump oil to shore or to operate submersible pumps in the wells) and water injection (for water flood or disposal). Other activities such as lighting, cooking, and process motor operation would consume lesser amounts of power.

Table V-3. ESTIMATED NUMBER OF PLATFORMS TO BE INSTALLED DURING LEASE SALE NO. 53 OCS ACTIVITY[1]

Zone	Year Installed	Low Resource Estimate		High Resource Estimate		Mean Resource Estimate	
		Production[2]	Other[3]	Production[2]	Other[3]	Production[2]	Other[3]
Kel River	1985	--	1	1	--	1	--
	1986	--	--	--	1	--	1
	1987	--	--	1	--	--	--
Point Arena	1985	1	1	1	1	1	1
	1986	--	--	--	--	--	--
	1987	--	1	1	1	--	1
	1988	--	--	--	1	--	1
Bodega	1985	1	1	1	1	--	--
	1986	--	--	--	--	1	1
	1987	--	--	1	--	--	--
Santa Cruz	1985	1	1[4]	2	1[4]	1	1[4]
	1986	1	--	2	--	1	1
	1987	--	--	2	1	1	--
	1988	1	--	1	1	1	--
Santa Maria	1985	2	1[4]	2	1[4]	2	1
	1986	1	--	4	1[4]	3	2[4]
	1987	1	--	4	1	2	1
	1988	2	--	3	1[4]	2	--
	1989	--	--	2	1	2	1
	1990	--	--	2	1	--	--

1. Source: USGS development scenario for Lease Sale No. 53 (1979). It is assumed that platforms are installed the year prior to the year in which they are expected to become operational.
2. Production platforms include both deep water and conventional platforms.
3. Platforms designated as "other" include floating production systems, offshore storage and treatment facilities (OS&Ts) and gas processing platforms (in the Santa Maria Zone only).
4. These platforms would not exist in Scenario 1A due to the existence of an onshore oil and gas processing plant.

Table V-4. PIPELINES EXPECTED TO BE INSTALLED DURING LEASE SALE NO. 53 OCS ACTIVITY[1]

		Length of Pipeline (miles)											
		Scenario 1			Scenario 1A			Scenario 2			Scenario 3		
Zone	Pipeline Type	95%	5%	Mean	95%	5%	Mean	95%	5%	Mean	95%	5%	Mean
EEL RIVER	Subsea Gas[2]	13	23	13	13	23	13	13	23	13	13	23	13
	Overland Gas	5	5	5	5	5	5	5	5	5	5	5	5
POINT ARENA	Subsea Gas[2]	13	13	13	22	22	22	13	13	13	13	13	13
	Overland Gas	33	33	33	35	35	35	33	33	33	33	33	33
	Subsea Oil[2]	--	5	--	--	5	--	--	5	--	--	5	--
BODEGA	Subsea Oil[2]	--	5	--	--	5	--	--	5	--	--	5	--
SANTA CRUZ	Subsea Gas[2]	55	75	59	55	75	59	55	75	59	55	75	59
	Overland Gas	7	7	7	7	7	7	7	7	7	7	7	7
	Subsea Oil[2]	55	75	59	55	75	59	55	75	59	55	75	59
	Overland Oil	87	87	87	87	87	87	--	--	--	--	--	--
SANTA MARIA	Subsea Gas[2]	45	65	46	45	65	46	45	65	46	45	65	46
	Overland Gas	14	14	14	14	14	14	14	14	14	14	14	14
	Subsea Oil[2]	45	65	46	45	65	46	20	40	30	20	40	30
	Overland Oil	54	54	54	54	54	54	--	--	--	--	--	--

1. Source: USGS development scenario for Lease Sale No. 53 (1979).

2. Includes both delivery lines and gathering lines.

The generation of power for the above operations would be the only major stationary source of combustion related pollutants during the production phase of OCS Lease Sale No. 53 activity. These emissions would be the main source of nitrogen oxides (NO_x), carbon monoxide (CO) and total suspended particulates (TSP) in the production phase.

A variety of oil- and gas-fired turbines and reciprocating engines is now used to generate power on offshore platforms (Energy Resources Co., 1977). The current trend in the industry, however, is thought to be toward the use of turbines. Recognizing this, it is expected that most of the power generation on Lease Sale No. 53 offshore platforms would be done by a combination of oil- and gas-fired turbines. To be conservative, however, all emissions associated with production power generation assume the use of diesel fired turbines.

The actual emissions associated with the generation of power on an offshore platform would vary with the size of the platform, the activities occurring at a given time, and the level of production on the platform. To estimate emissions, it has been necessary to assume "typical" values for installed power and power usage for the different activities occurring on a platform. These, as well as other assumptions used in estimating the emissions are described in Production Power Generation, in Section V.D.1.

ii. Oil and Gas Production

When oil and gas are produced from a well, the product is typically an oil/gas/water mixture. To produce a usable product, the oil and gas must be separated, purified, and dehydrated. A brief description of this process follows.

a) Gas Processing

The oil/gas/water mixture produced is pumped to a separator where the gas and gas-liquid are separated from the oil and water. Raw gas containing water and some liquid hydrocarbons is then dehydrated prior to piping it to a processing plant or platform. The initial separation of the raw gas from the oil/water mixture is normally done on the platform producing the oil and gas. Dehydration is also done on the platform to avoid the formation of hydrates in processing equipment or pipelines.

The major sources of emissions during processing operations would be leakage from the separation units and combustion of fuel to supply heat to the dehydration units. In addition, fugitive emissions from compressors, pump seals and pipe valves would occur in smaller quantities. These emissions and the methods used to determine the quantity of each are presented in Section V.D.1.

The dehydrated gas, still containing liquid hydrocarbons and other pollutants such as hydrogen sulfide,is then piped to the processing area, which may either be an onshore plant (as in BLM Transportation Scenario 1A) or a central platform. Here, the gas is separated from the remaining liquids, and desulfurized using any of a number of commercial processes.

Emissions generated during separation and desulfurization operations would include hydrocarbons (HC) from leakage and venting, hydrogen sulfide

(H_2S) contained in lost raw gas and sulfur oxides (SO_x) from the incineration of tail gas in the desulfurization process. In estimating these emissions, it was assumed that the emissions from gas processing in Lease Sale No. 53 would be similar to those presented in the Lease Sale No. 35 report by Leach (1975) for gas production and processing. The estimated hydrocarbon emissions presented in the Lease Sale No. 35 analysis, however, are based on an emission factor for onshore processing plants. Due to improved technology and the fact that offshore plants may require tighter controls for safety reasons (Energy Resources Co., 1977), the hydrocarbon emissions associated with gas processing may be overestimated.

b) Oil Processing

The oil produced in the wells would be in an oil/gas/water mixture, as described earlier. The oil must be separated from this mixture and upgraded to a pipeline quality, free of water and solids. The first step would be to separate the oil/water mixture from the gas, described earlier. The next step is to pass the oil through a series of separators to remove free water. After this step, the oil still contains water in an emulsion. To break the emulsion, the oil is heat treated, reducing the water content to less than one percent (Energy Resources Co., 1977). The oil is then either pumped to shore or to an offshore storage and treatment facility to await tankering.

The emissions associated with oil processing would be hydrocarbons from evaporation, and combustion generated pollutants from the heat treating of the oil.

In comparison with other pollutants emitted during the production and processing phase, the emissions associated with oil processing are not expected to be highly significant. They have, however, been estimated and the assumptions and methods used are presented in Section V.D.1.

iii. Fugitive Sources

Fugitive losses are expected to be a large source of hydrocarbon (HC) emissions. In most cases such emissions would be exceeded only by gas processing and tanker loading in the quantity of hydrocarbons emitted.

The major sources of evaporative emissions would be pump and compressor seals, relief valves, oil/wastewater separation units, and valves and flanges on pipelines. The amount of pollutants emitted would depend upon the production level being considered and the controls applied on each individual platform. The assumptions used in estimating the total quantity of fugitive emissions are presented in Section V.D.1.

iv. Supportive Activities

Support activity during production is not expected to be as high as it would be during the development phase. Once all wells are drilled and the platforms installed, it is expected that the demand for supplies and men would decrease. One supply or crew boat would then be able to service a number of platforms at a time. The number of trips, and thus the emissions associated with support activity, would decrease.

The assumptions made concerning the number of platforms each ship would be able to support, as well as specific assumptions for each zone, are described in Section V.D.1.

d. Accidents

An accidental oil spill or fire has the potential for creating a significant air pollution problem. In this section, an effort is made to estimate both the risk of a serious accident and the amount of emissions which would result from it.

i. Types of Accidents and Probabilities

Historical data on oil spills associated with oil and gas development within the U.S. OCS areas are compiled annually by the U.S. Geological Survey. Operational oil spill statistics for activities in the Gulf of Mexico are quite useful as a statistical base for predicting spill frequencies and volumes because of the high level of development and the extent of data kept. During the period 1964 through 1976, 54 spills larger than 50 barrels occurred in the Gulf of Mexico (Bureau of Land Management, 1979a). The types of accidents leading to these spills included blowouts, pipeline breaks and leaks, fires, tanker or barge spills, ship collisions and production equipment malfunctions. A summary of the number of spills of more than 50 barrels of oil, the total amount of oil lost, and the causes are presented in Table V-5. The Bureau of Land Management (1979a) used these data to estimate the quantities of oil which may be expected to be spilled in accidents of 1,000 barrels of more over a 20 year period. The numbers of spills of at least 1,000 barrels which are statistically expected are 1.8 spills at the platform per billion barrels produced, 2.3 spills associated with the pipeline per billion barrels transported and 3.9 spills associated with tankers per billion barrels shipped. Beyer and Painter (1977) have also examined the U.S. Geological Survey data for OCS operations. Their data base incorporated information for the period 1966 through 1975 on both Gulf of Mexico and Pacific Coast activities. They calculated prediction parameters for pipeline accidents, blowouts, natural phenomena, platform fires, platforms overflows and malfunctions and small 50 barrel spills which are related to production (See Table V-7). From this information an average spill rate, from all causes of 72 barrels per million barrels produced was projected. They also report data on worldwide tanker casualty spills between 1969 and 1972. A casualty spill involves rupture of a cargo tank from collision, grounding, structural failure, etc. Spills related to handling cargo, e.g., valve leaks, tank overflows, hose leaks, were not included. Overall, 522 casualty spills occurred in coastal waters in four years, with the average spill size being 7,100 barrels. Relating casulaty spills to tanker sizes, 475 spills occurred worldwide from tankers of less than 40,000 DWT capacity. The average spill size in this instance was 2,200 barrels.

It should be noted that the majority of spills are not on the order of thousands of barrels. In 1972, 85 percent of all spills resulted in less than 100 gallons being spilled per accident; and 96 percent of all spills involved less than 1,000 gallons per incident (Bureau of Land Management, 1979a).

Both the frequency of large spills -- at least 1,000 barrels spilled -- and the total amount of oil which might be spilled during 20 years of development can be estimated from these two studies and the mean resource estimate. Table V-6 shows the frequency of large spills expected in each zone and Table V-7 shows the total amount of oil expected to be spilled per zone.

a) Blowouts

Blowouts are usually the result of equipment malfunctions, workover procedures, human errors, storms and collisions, and not of drilling (Bureau of Land Management, 1979a). Gulf of Mexico statistics indicate an average of one blowout for every 231 wells drilled. The average spillage for each blowout was 1,053 barrels of oil. During the study period of 1956 to 1976 for the Gulf of Mexico, only eight blowouts resulted in large spills, i.e., spills over 50 barrels of oil. The impact of the Campeche Bay blowout and fire in the Gulf of Mexico and other recent accidents on these data is not yet known.

b) Tanker-Related Accidents

Collected statistics of tanker-related oil spills range from a few gallons to 150,000 barrels. During the period 1964 to 1976, the oil spill data for the Gulf of Mexico given in Table V-5 lists 54 pollution incidents of 50 barrels or more resulting from federal OCS oil and gas operations. Most spills are of low volume: in 1972, 96 percent of the spills were less than 24 barrels (1,000 gallons) and 85 percent were less than 2.4 barrels (100 gallons) (Bureau of Land Management, 1979a). Among the causes of small spills are leaks in pipes or hoses, failure of pumps or valves, and human errors in handling the equipment. Larger spills may occur if a tank overflows or if a tank or pipeline ruptures. The most severe spills have been produced by collisions or explosions. The grounding of the ARGO MERCHANT and the explosion aboard the SANSINENA are two such events.

c) Pipelines

The number of pipeline failures associated with Gulf of Mexico OCS operations has been reduced since the implementation of USGS OCS Operating Orders on pipeline operations. Since the orders have gone into effect, Gulf of Mexico pipeline breaks and leaks contributed 29.0 percent of the significant pollution incidents (27.7 percent of oil spilled). Oil spillage in the Gulf of Mexico due to pipeline accidents amounts to about 0.0014 percent of the total production, with 72.9 percent of the total volume spilled by pipelines and 37.5 percent of the accidents being due to ship anchors dragging across pipelines and rupturing them (Bureau of Land Management, 1979a).

d) Oil Fires

Oil spills from explosions and fires typically are the result of combustible hydrocarbon liquids or vapors coming in contact with electrical or overheated mechanical devices on offshore platforms. Explosions or fires may also result from ignition of combustible hydrocarbons by lightning or static electricity. Gulf of Mexico data indicates one explosion and fire was statistically associated with the drilling of 74 wells, with an average spill volume of 461 barrels of oil (Bureau of Land Management, 1979a).

ii. Emissions

For this study, the oil spill scenario provided by BLM and previously used by AeroVironment Inc. for Lease Sale No. 48, is used in emission calculation. According to this scenario emissions would be associated with 1) instantaneous oil spills of 140 barrels and 10,000 barrels; 2) a blowout of 1,000 barrels

Table V-5. OIL SPILLS GREATER THAN 50 BARRELS IN THE GULF OF MEXICO, 1964-76

Cause of Spill	No. of Accidents	% of Accidents	Barrels of Oil Spilled	% of Oil Spilled
1. Blowout	5	9.1	5,138	1.6
2. Hurricane Damage*	6	10.9	14,357	4.4
3. Pipeline Breaks & Leaks				
a. Unknown Cause	7	12.7	8,209	2.5
b. Corrosion	4	7.3	5,564	1.7
c. Anchor Dragging	5	9.1	186,652	57.2
	(16)	(29.1)	(200,425)	(61.4)
4. Fires	1	3.6	30,600	9.4
5. Barge Spills	3	5.5	7,340	2.2
6. Collisions	3	5.5	2,825	0.87
7. Production Equipment Malfunction				
a. Valves	4	7.3	365	0.11
b. Overflow of Vessel or Tank	10	18.2	1,113	0.34
c. Workover	1	1.8	53,000	16.2
d. Well Abandonment	1	1.8	500	0.15
e. Other Equipment Failures	4	7.3	10,500	3.2
Subtotal	(20)	(36.4)	(65,478)	(20.0)
TOTAL	54	100.1	326,163	99.87

* Hurricanes are not likely to be a cause of oil spills off the coast of California.

Source: Bureau of Land Management, 1979a.

Table V-6. NUMBER OF STATISTICALLY EXPECTED OIL SPILLS OF 1,000 BBLS OR MORE DIRECTLY RELATED TO OCS SALE NO. 53 DURING 1986-2005[1]

(MEAN RESOURCE ESTIMATE)

	Source of Spill					
Lease Tract	Platform	Pipeline (Scenario 1)	Tankers (Scenario 1)	Tankers (Scenario 1,2)	Blowout	Fire
Point Arena	0.24	—	0.52	0.52	0.38	1.2
Bodega	0.04	—	0.09	0.09	0.11	0.35
Santa Cruz	0.22	0.28	—	0.48	0.59	1.8
Santa Maria	0.74	0.94	—	1.6	1.5	4.7
	1.24	1.22	0.61	2.69	2.58	8.05

Source: Department of Interior, Final Environmental Impact Statement, OCS Sale No. 48, 1979.

1. Based on historical data collected from all U.S. OCS activity, the number of statistically expected spills of 1,000 bbls or more in 20 years are: platform related, 1.8 spills/10^9 bbls produced; pipeline related, 2.3 spills/10^9 bbls transported; tanker related, 3.9 spills/10^9 bbls transported.

Table V-7. ESTIMATE OF SPILL OIL PREDICTED IN MEAN RESOURCE ESTIMATE FOR OCS LEASE SALE NO. 53 (1986-2005)[1]

Source of Spill	Prediction Factors	Total Quantity of Oil Spilled in Spills Larger Than 50 bbl (barrels) in Each Zone			
		Point Arena	Bodega	Santa Cruz	Santa Maria
Platform	6.1 bbls/10^6 bbls produced	788	142	712	2,436
Pipeline - Scenario 1 or 1A	13 bbls/10^6 bbls produced	N/A[2]	N/A[2]	1,517	5,191
Tankers - Scenario 1 or 1A	2.2 bbls/port call	1,621	2,042	N/A[3]	N/A[3]
Scenario 2	2.2 bbls/port call	1,621	2,042	2,567	4,413
Scenario 3	85 bbls/10^6 bbls transported	10,974	1,972	9,920	33,940
Blowouts	24 bbls/10^6 bbls produced	3,098	557	2,801	9,583
Fires	26 bbls/10^6 bbls produced	3,357	603	3,034	10,382
Minor Spills - 50 bbl each	2.6 bbls/10^6 bbls produced	336	60	303	1,038
Natural Phenomena	0.7 bbls/10^6 bbls produced	90	0[4]	82	280

1. Source: Beyer and Painter, 1977.
2. All oil from this zone would be transported by tanker or barge.
3. Under these transportation scenarios, oil would be transported by pipeline.
4. The zero does not mean no oil would be spilled as a result of such natural phenomena as seepage, earthquakes or storms; it means that no oil spill of 50 bbl or more is predicted to result from natural phenomena.

per day with an associated 1,000,000 standard cubic feet (scf) of gas per day which does not ignite; and 3) a blowout of 1,000 barrels of oil and 1,000,000 scf of gas per day with a fire. The resultant emissions associated with these events are presented in Table V-70 in Section V.D.5. Emission factors used for these calculations and and listed in Table V-89 were previously derived based on the characteristics of Dos Cuadras crude oil (Bureau of Land Management, 1979a).

a) Hydrocarbons

Crude oil composition varies with the source. Most crude oils are composed of at least 75 percent hydrocarbons. Evaporation of the more volatile components may occur from the surface of the spill or from oil in sea water droplets which are lifted into the air by eddy currents. Data necessary to estimate hydrocarbon emissions from spills or blowouts include the amount of volatile material in the crude oil and the extent and rate of volatilization. Work reported by AeroVironment (1977) indicated 50 percent of the volatiles evaporate in the first hour and 75 percent are lost after two hours. In the case of oil fires, incomplete combustion of the hydrocarbons would be expected. A value of 100 pounds per ton (95 percent combustion of hydrocarbons in a fire), was used to estimate emissions associated with development of Lease Sale No. 48 (AeroVironment, 1977).

b) Sulfur Compounds

Hydrogen sulfide and related sulfur compounds could be emitted in the gas lost during a blowout. Hydrogen sulfide should be considered for its air pollution potential, but heavy sulfur compounds in the oil may be considered nonvolatile. Should a fire occur with a blowout, all sulfur compounds may be considered to be oxidized to sulfur dioxide.

c) Nitrogen Oxides

Nitrogen oxides can be produced in a fire. Emissions will be dependent upon the combustion conditions, which could be highly variable, sometimes resembling an open burning situation and sometimes resembling combustion in a furnace. Emission factors were developed at the University of California at Los Angeles (1978) from combustion chamber experiments. According to the UCLA work, the following emissions would result per barrel of oil burned: 11 pounds of hydrocarbons, 0.34 pounds of nitrogen oxides, 30 pounds of carbon monoxide, 6.3 pounds of sulfur dioxide and 11 pounds of particulates. The values for hydrocarbons, nitrogen oxides and sulfur oxides are less conservative than emission factors quoted by AeroVironment (1977) in preparing emissions estimates for OCS Lease Sale No. 48. In order to compare emissions predicted from Lease Sale No. 48 activities with Lease Sale No. 53 activities, the emission factors quoted by AeroVironment (1977) were used.

d) Carbon Monoxide

Carbon monoxide emissions are only produced in conjunction with a fire and have been assumed to equal the emission rate for unburned hydrocarbons (AeroVironment, 1977).

e) Particulate Matter

AeroVironment (1977) reports, "Particulates are produced during fires from ash resulting from non-combustibles in the oil and from soot that is generated by incomplete combustion. The ash content of these crudes is approximately 0.1 percent and particulates from soot would be expected to be greater. A factor of one percent for total particulates was chosen which is larger than the burning of municipal waste, scrap wood and agricultural waste and similar to that cited for the burning of automobile components."

2. Offshore Storage, Transfer and Transport of Gas and Oil

Whenever gas is produced in sufficient quantity for sale in Lease Sale No. 53, it would be transported to shore through pipelines. Crude oil recovered could be transported to refineries onshore either through pipelines or by ships (tankers and barges). The final selection of the transport methods and destinations would depend upon numerous factors including, among others, the quantity of oil or gas to be recovered, the production rate, the transportation distance required, constraints imposed by governmental regulations, and the costs associated with a specific transport mode.

The Bureau of Land Management has developed four Transportation Scenarios as possible means for bringing recovered oil and gas ashore. For all areas with adequate quantities of gas, Scenarios 1, 2 and 3 would have the gas completely treated and processed offshore and then compressed and pumped to shore via pipeline. Under Scenario 1A, the gas would receive only minimal treatment offshore before entering a pipeline leading to an onshore processing facility. In all cases, the fully treated, compressed gas would continue its movement in onshore pipelines to connect with existing utility operated commercial pipelines.

Oil would be transported by both tankers and pipelines under Scenarios 1 and 1A. Ships would bring oil from the Point Arena and Bodega zones to refineries in the San Francisco area. Oil would not be expected to be recovered from the Eel River zone. Pipelines would carry oil ashore from the Santa Cruz and Santa Maria zones. From Santa Cruz, oil would ultimately be pipelined to the San Francisco area. Crude oil recovered from the Santa Maria zone would pass through the proposed Santa Barbara County pipeline in Los Flores Canyon to refineries in the Los Angeles area.

Scenario 2 proposes that tankers or barges transport all oil to shore. Oil from the Point Arena, Bodega and Santa Cruz zones would be sent to San Francisco; whereas oil recovered from the Santa Maria zone would be shipped to Los Angeles.

Under Scenario 3, all oil would be tankered directly from the production area through the Panama Canal to Gulf Coast ports, e.g., Galveston, Texas. It should be stressed that the ships are assumed to leave the California Coastal Waters as expeditiously as possible.

The size of the ships and the frequency of trips depend upon the amount of oil produced and the shipping distances involved. The types of ships or barges expected to be used are listed in Table A-42, in Appendix A, and the anticipated frequency of their trips is given in Tables A-47 through A-49 in Appendix A.

a. Tankers/Barges

There are several routine types of emissions associated with the operation of either a tanker or barge: 1) hydrocarbon losses from loading crude oil; 2) exhaust emissions from burning residual oil or diesel fuel in the ship's engines and pumps; 3) hydrocarbon losses from taking on ballast into non-segregated cargo tanks for tankers; and 4) hydrocarbon losses from cargo tanks breathing while the ship is in transit. A non-routine act which generates high levels of hydrocarbons is purging a ship's tanks. Accidental spills, with or without an ensuing fire, can also be a significant source of emissions.

i. Loading Losses

Hydrocarbon vapors would be produced and emitted as a result of two conditions present during loading of either tankers or barges (OPR, 1976). First, there is a hydrocarbon-air mixture in the empty cargo tanks which would be displaced by incoming crude oil. The amount of hydrocarbons present in this mixture depends on whether the tank has been gas-freed, partially gas-freed, ballasted, or left empty and uncleaned. The second major cause of tanker-related hydrocarbon emissions would be gas generation resulting from the turbulence of the oil cargo during the loading operation. Turbulence would be reduced after the loading fillpipe is submerged. If there is little agitation, a rich volatile hydrocarbon vapor blanket would be able to form over the surface of the oil; because the hydrocarbon vapors would be denser than air, they would stabilize above the liquid cargo and prevent further gas generation.

There is no consensus about the technical validity of loading emission factors; numerous factors are therefore available to calculate hydrocarbon losses. A recent study by Chevron Research Company (1977) of emissions from loading crude oil at two Ventura County, California marine terminals concluded that an average of 0.97 pounds of hydrocarbons were released per 1,000 gallons loaded. This emission factor is the arithmetic average of a number of Chevron's tests. This factor was selected as suitable for calculating loading losses from Lease Sale No. 53 activities because of the expected similarities between the crude being loaded in Ventura County and the crude oil expected to be recovered.

Barges are shallower than tankers and thus have larger surface areas than tankers with similar capacities. Enlarging the surface area increases the likelihood of volatile components of the crude escaping. Thus, the emission factor for hydrocarbon losses from loading barges should be higher than for tankers. An emission factor for barges that was three times higher than for tankers was given by AeroVironment (1977). Consistent with the 0.97 pounds of hydrocarbons released per 1,000 gallons of crude oil loaded into a tanker, the emission factor for loading a barge is 2.9 pounds of hydrocarbons released per 1,000 gallons of oil loaded.

ii. Breathing Losses

Hydrocarbons can escape from cargo tanks through either the ullage hatches or pressure vacuum vent valves as a result of changes in barometric pressure, temperature or vapor growth. These breathing or venting emissions have been considered in this study as contributing to hydrocarbon losses in all transit and hoteling activities performed by tankers. The emission factor was derived from data given by the U.S. EPA (1977).

iii. Ballasting Losses

Ballasting a tanker[1] requires adding enough weight to the ship by taking on water into empty tanks to maintain stability and maneuverability. If there are hydrocarbon vapors in the empty tanks, the incoming water will displace these gases, thereby producing emissions. In order to estimate potential emissions conservatively, two assumptions were made about the activities of a tanker in port. First, it was assumed that a tanker would ballast up to 20 percent of its capacity in port. Second, it was assumed that one-half of the tankers coming into port would not have segregated ballast capacity. This was done because the exact equipment specifications of the tanker fleet is not known. Also, it is anticipated that even though existing tankers of less than 40,000 DWT would not be required by the Coast Guard's proposed implementation of Intergovernmental Maritime Consultive Organization protocols to have segregated ballast capacity (Federal Register, April 29, 1978), the majority of tankers would be able to duct escaping vapors through a common cargo tank vent. Such a vent would be necessary should a requirement for vapor recovery during cargo loading be mandated (California Air Resources Board, 1978).

iv. Purging (Gas-Freeing) Losses

Purging is a process of displacing all hydrocarbon vapors in a cargo tank with an inert gas to eliminate potentially toxic or explosive conditions. Gas-freeing differs from purging in that air replaces the hydrocarbons which are vented to the atmosphere.

Purging is a discretionary action which is seldom expected to occur. It is anticipated that purging or gas-freeing would be done only if the tanker needed a very thorough inspection or repairs. The potential hydrocarbon emissions would be high and relatively long lasting -- about 30 hours.

v. Combustion Emissions

Fuel combusted to power a ship's engines and pumps would result in emissions at the offshore facilities, in port, and along the sea lanes whenever the ship is in transit. Of primary concern are the quantities of sulfur oxides and nitrogen oxides produced. The amount of emissions would depend primarily upon the fuel sulfur content, the fuel consumption rate and the duration of a given activity. The latter two parameters would be influenced by the size of the ship.

Tankers to be used to transport oil were assumed to be steamships. Steamships are powered by boilers, which are combustion units that convert water into steam. Fuel consumption rates, presented in Table A-44 in Appendix A, were estimated based on data from the California Air Resources Board (1978) and Woodward-Clyde Consultants (1979b).

Two grades of residual oil were assumed to be needed by the steamships: fuel containing 0.5 percent sulfur would be required when a tanker is in

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1. Barges do not take on ballast (California Air Resources Board, 1978).

port, and fuel containing 2.0 percent sulfur would be used at all other times. While there are no formal regulations in the San Francisco Bay Area or Los Angeles harbors restricting tankers to the in-port use of 0.5 percent sulfur fuel, past experience in marine terminal projects (for example, Standard Oil of Ohio, Port of Long Beach, 1978; ARCO, Port of Long Beach, 1979; Wickland Oil Terminal, State Lands Commission, 1979) suggests that permitting would not occur without the low sulfur fuel restriction.

Tugboats would be needed to tow barges between the offshore facilities and the port as well as to aid tankers into and away from the dock. Tugboats would be diesel motor ships with either 800 horsepower or 2,000 horsepower engines, depending upon the size of the barge or tanker being moved. Fuel consumption rates, presented in Table A-44 in Appendix A, were taken from data presented by Goodley et al., (1977).

vi. Tankering Technical Assumptions

For each zone, the length of time necessary for each tankering operation was estimated and is presented in Appendix A along with per visit emissions associated with tankering in each area. The assumptions made are as follows:

1) All vessels under Transportation Scenarios 1, 1A or 2 would travel at 15 knots in the open ocean and at six knots in the immediate vicinity of the OS&T and of the port. In San Francisco, the tanker was assumed to travel at six knots when landward of the Golden Gate Bridge; and in the Los Angeles/ Long Beach area the tanker was assumed to travel at six knots for the three miles landward of the port buoy (Woodward-Clyde Consultants, 1979a);

2) All vessels under Transportation Scenario 3 would travel at an average of 16 knots in the open sea; and

3) Tankers would be capable of loading and unloading at the rate of 20,000 barrels/hour. Barges would have pumping rates which vary with the cargo capacity as presented in Table V-8.

The turnaround times resulting from these assumptions are given in Table A-43 in Appendix A. If any assumption about the operating mode of a ship should be changed, the estimated emissions would likewise change. For example, if the transit time of a vessel were to be increased, the mobile emissions would also be increased as a result of more fuel being used and more hydrocarbon breathing losses occurring.

vii. Emission Factors and Calculations

The emission factors used in the estimation of tanker/barge emissions and the appropriate references are presented in Tables A-45 and A-42 in Appendix A.

Major technical assumptions made in order to calculate predicted emissions are as follows:

1) Loading losses - Loading losses would be three times larger for a barge than for a tanker because of the larger surface area on a barge. All the tankers would be loaded at an offshore storage and loading facility. No vapor recovery is assumed for tanker loading.

2) Breathing losses - Breathing losses would occur whether the ship was in motion or docked.

3) Control technology - Because the makeup of the tanker fleet is unknown, it was assumed that no inerting systems would be operational, no crude oil washing would be done and half the tankers docking at California ports would take on 20 percent capacity as ballast while in port into non-segregated ballast tanks. In addition, the OS&Ts were assumed to be equipped with vapor balance lines. Therefore, hydrocarbon emissions associated with the transfer of product oil from a platform to the OS&T would be insignificant.

4) Tugboat assistance - The length of time tugboats would assist a ship would vary with the port. Specific information about the ports of San Francisco and Los Angeles were used in the appropriate cases. (See estimates of emissions on a per visit basis in Tables A-50-A-64.)

5) Time requirements for maneuvering and hoteling - The length of time a ship would be maneuvering to and from an OS&T or into and away from an onshore dock was based on data from Exxon Company, U.S.A., the Port of San Francisco and the Port of Long Beach. The amount of time spent hoteling assumed an operation with no delays, yet with no time-saving measures such as simultaneous ballasting and offloading. (See estimates of emissions on a per visit basis in Tables A-50 - A-64.)

6) Purging/Gas-Freeing - Discretionary emissions such as purging/gas-freeing were not included in annual emissions estimates.

7) Pumping - The power needed by pumps to load or offload crude oil is supplied by the ship itself. The power needed by pumps to load crude oil is supplied by the OS&T in the cases of barges and smaller tankers traveling between the OS&T and California ports.

b. Pipeline

According to the USGS transportation scenarios, wherever suitable quantities of gas are recovered, it would be transported by pipeline to shore and ultimately into a commercial gas pipeline for sale and use. Oil from the Santa Cruz and Santa Maria zones would be transported to shore by pipeline under Transportation Scenarios 1 or 1A. Then the oil from the Santa Cruz zone would be routed through existing or proposed pipelines to refineries in the San Francisco area, and the oil from the Santa Maria zone would be transported through existing or proposed pipelines to refineries in the Los Angeles Area.

Fluids from a number of wells would be brought to the platform for an oil/gas separation. The oil would then be pumped directly to shore.

The gas could be treated in two ways. According to Transportation Scenarios 1, 2 and 3, gas would be processed offshore to a commercially acceptable quality. It would then be compressed and shipped directly to utility supply pipelines. In Scenario 1A, the gas processing plant would be onshore. However, it would be necessary to dehydrate the gas at the platform before compressing it and transporting it ashore. Then, after the gas had been suitably treated and compressed, it would reenter pipelines leading to the point of sale.

Major sources of onshore emissions associated with temporary and permanent service bases would include those from crew and supply boats operating in port, helicopters transporting personnel from onshore to offshore areas and back, and employees' vehicles. Pollutants emitted in the greatest quantities from these onshore emission sources would be nitrogen oxides and carbon monoxide.

Emissions associated with platform fabrication have not been estimated since the location of such construction is uncertain. Platform construction requires tremendous space that is already in short supply in port areas of San Francisco, Los Angeles, and San Diego. Some of the platforms needed for OCS development of Lease Sale No. 53 areas may be constructed in established facilities in the Gulf of Mexico area.

2. Onshore Transfer, Transport, Storage and Processing of OCS Products

a. Onshore Emissions Associated with Transportation of Oil and Gas

Onshore emissions associated with transport, transfer, and processing of OCS products would include those from overland pipeline construction, from tankers or barges hoteling and unloading in port, and from onshore crude oil storage tanks and oil and/or gas processing plants. The extent of onshore activities would vary among the five zones, so not all areas would have all these potential emission sources.

Onshore pipelines would be used for the transport of gas in every transportation scenario and in every zone except Bodega. If BLM Transportation Scenarios 1 or 1A were adopted, oil from the Santa Cruz and Santa Maria zones would be transported to the San Francisco, and Los Angeles areas by pipeline. Emissions associated with overland pipeline installation have been estimated, and have shown that the pollutant of primary concern would be nitrogen oxides. Emissions associated with the operation of the pipelines have not been included as part of the onshore emissions for two reasons 1) the power generation facilities required would be located offshore; and 2) most of the fugitive emissions from valves, flanges, and pump seals would occur offshore.

Onshore emissions associated with tanker and barge unloading are discussed in Section V.B.2. Emissions resulting from fuel combustion would occur while a tanker or barge hotels and unloads crude oil in port. The major in-port tanker-related emission would be hydrocarbons lost when taking on ballast into unsegregated tanks. Barges would not require ballast and thus would not have large in-port hydrocarbon emissions. It should be noted that onshore emissions from tankers and barges may occur in ports quite distant--up to one hundred miles--from the OCS zone with which they are associated. (Tanker-related emissions which would occur in Galveston, Texas under Transportation Scenario 3 have not been estimated).

b. Onshore Emissions Associated with Storage of Crude Oil

Under Transportation Scenario 1A, two 50,000 barrel onshore storage tanks have been proposed for the Santa Cruz zone and two 170,000 barrel onshore storage tanks have been projected for the Santa Maria zone. Evaporative hydrocarbon losses from these tanks were estimated assuming that the use of floating roofs with double seals represented the Best Available Control Technology

(BACT). The hydrocarbon emissions from these storage tanks are not considered to be a significant portion of the total hydrocarbon emissions associated with each zone.

c. Onshore Emissions Associated with Oil and Gas Processing

Other onshore emissions would result from onshore oil and/or gas processing plants. Except in the Bodega zone, Transportation Scenario 1A proposes onshore oil and/or gas processing plants. The primary sources of emissions would be heater treaters used in oil processing and dehydration, and desulfurization units and fugitive losses of hydrocarbons in the gas processing plant. In addition to the large quantities of hydrocarbons, smaller quantities of sulfur dioxide and hydrogen sulfide would be emitted. Emissions associated with a gas processing plant would represent the single highest rate of hydrocarbon emissions in a zone on an annual basis.

d. Emissions Associated with the Refining of Lease Sale No. 53 Crude Oil

Based on information provided by BLM, no new refineries are expected to be required as a result of Lease Sale No. 53 (BLM, 1979b). Three of the Transportation Scenarios supplied by BLM (Scenarios 1, 1A and 2) project the refining of Sale No. 53 crude oil at existing facilities in the San Francisco and Los Angeles areas.

There may be some changes in the emissions from those refineries processing Lease Sale No. 53 crude oil if the properties of the Sale No. 53 oil are significantly different from those of the oil presently being processed. Due to these differences and differences in the processing designs of each refinery, estimating exact changes in refinery emissions is extremely difficult and speculative. However, major changes in emissions in the areas of concern can be approximated.

BLM has estimated that, for a 20 year average during the period 1986 to 2006, crude oil from Lease Sale No. 53 would utilize approximately 6.0 percent of the refinery capacity in the San Francisco Bay area and 8.2 percent of the refinery capacity in Los Angeles (BLM, 1979b). Changes in emissions would be related to the refinery capacities affected and to differences in the composition of the relevant crude oil.

The limiting factors in refining Lease Sale No. 53 crude oil were assumed to be the specific gravity of the produced oil, as defined by the American Petroleum Institute (API gravity), and the sulfur content of the crude oil (BLM, 1979b). These factors were also assumed to have the most influence upon refinery emissions. By comparing differences in the API gravity and sulfur content of Lease Sale No. 53 crude oil with that crude oil being displaced, incremental changes in refinery emissions could be roughly estimated.

The distribution of API gravities of the crude oil refined in California in 1975 is presented in Table V-10.

It is assumed that the 1975 data would represent the crude oil refined in California which would be replaced by oil from Lease Sale No. 53.

The average API gravity of the crude oil expected to be refined in California at the time of Lease Sale No. 53 production is 21.5. This value was obtained by averaging each individual range of API gravities presented in Table V-10, relating the API number to percent of production, and calculating an average API gravity of all oils refined in California. The average API gravity of Lease Sale No. 53 crude oil is estimated to be 24 (BLM, 1979b). A higher API gravity represents lighter products. Generally, less energy would be required to process lighter crudes. Therefore, on an average basis, no significant changes in refinery emissions would be expected if some of the existing imported crude oil in California refineries is replaced by Lease Sale No. 53 crude oil.

The second factor which may influence emissions from refineries is the sulfur content of the crude oil. The average sulfur content of crude oil refined in California in 1975 was 0.90 percent sulfur by weight (The Pace Company, 1977). Again, data from 1975 was used to approximate the crude oil which would be refined in California when production from Lease Sale No. 53 occurs. The average sulfur content of Lease Sale No. 53 crude oil is expected to be 2.5 percent sulfur by weight (BLM, 1979b). The sulfur content of Lease Sale No. 53 crude oil is significantly higher than the oil which it is expected to replace. Sulfur oxides, mainly sulfur dioxide, would constitute the major increase in emissions from refineries processing Lease Sale No. 53 crude oil.

Generally, the majority of sulfur oxide emissions from the refineries are the result of combustion of fuel oil in different process boilers or heaters. The sulfur content of these fuel oils may not be affected by an increase in sulfur content of a crude oil being processed. Realistically, the refining of a crude oil of higher sulfur would result in somewhat higher sulfur oxide emissions, although the increase would not be related only to the sulfur content of the crude oil refined. However, in order to approximate the maximum possible increase in sulfur oxide emissions, changes in the sulfur content of the crude oil was proportionately related to sulfur oxide emissions from refineries in the San Francisco and Los Angeles areas. Sulfur oxide emissions were approximated based on differences in the sulfur content of Lease Sale No. 53 crude oil and that oil expected to be replaced. Table V-11 presents maximum possible increases in sulfur oxide emissions due to the refining of Lease Sale No. 53 crude oil. Again, these incremental increases are rough conservative estimates of maximum possible changes in refinery emissions if OCS crude oil replaces some of the crudes otherwise refined in Los Angeles and San Francisco refineries.

Based on the above estimates, a maximum possible increase of approximately 2,164 tons per year of sulfur oxides could occur in the San Francisco area from refineries processing Lease Sale No. 53 crude oil. This would represent a 2.7 percent increase in total sulfur oxide emissions in the San Francisco Bay area (based on 1975 data). In Los Angeles, the refining of Lease Sale No. 53 crude oil could result in a maximum possible increase of 2,513 tons annually. This would represent a 1.6 increase in total sulfur oxide emissions in the Los Angeles area (based on data from 1975 to 1976). These emissions have not been included in the total values for the lease areas.

3. Onshore Supporting Labor Force for Offshore Activities

Onshore emissions resulting from activities of the personnel associated with the development of Lease Sale No. 53 have been estimated and listed in Section V.D.2. The major sources would be the cars carrying the employees to

Table V-10. DISTRIBUTION OF API GRAVITIES OF CRUDE OIL REFINED IN CALIFORNIA IN 1975

°API	Percent of Production
Less than 16	26.5
16-20	32.4
20-35	14.0
25-32	20.0
32-40	6.8
Greater than 40	0.3

Source: Conservation Committee on Oil Products (1977)

Table V-11. ESTIMATION OF INCREASES IN SULFUR OXIDE EMISSIONS FROM THE REFINING OF LEASE SALE NO. 53 CRUDE OIL

A. Sulfur Content of Crude Oils:

Type	Average Sulfur Content (Percent by Weight)
Crude Oil Expected to be Refined in California at the Time of Lease Sale No. 53	0.9[1]
Lease Sale No. 53 Crude Oil	2.5[2]

B. Increase in Average Sulfur Content of Crude Oil Refined Due to Replacement by Lease Sale No. 53 Oil:

Area	Average Sulfur Content (Percent by Weight)
San Francisco	0.996
Los Angeles	1.031

C. Existing Sulfur Oxide Emissions from Refineries:

Area	Sulfur Oxide Emissions (tons/year)
San Francisco	20,290[4]
Los Angeles	17,265[5]

D. Projected Maximum Possible Increments in Sulfur Oxide Emissions Due to Refineries of Lease Sale No. 53 Crude Oil in California:

Area	Sulfur Oxide Increases (tons/year
San Francisco	2,164
Los Angeles	2,513

1. Sources: U.S. Bureau of Mines (1977)
   SRI Chemical Economics Handbook ( )
   Oil and Gas Journal ( )
   The Face Company (1977).
2. Source: Bureau of Land Management (1979b).
3. Based on Lease Sale No. 53 crude oil replacing 6.0 percent of refining capacity in San Francisco and 8.2 percent of the refining capacity in Los Angeles (Bureau of Land Management, 1977b).
4. Source: Bay Area Air Pollution Control District (1977). Annual emissions are based on daily emissions multiplied by 365. Data is for the year 1975.
5. Source: South Coast Air Quality Management District, Southern California Association of Governments (1979). Annual emissions are based on daily emissions multiplied by 365. Data is for the years 1975 to 1976.

and from the service bases and helicopters shuttling between the base and the platforms. The primary pollutants of concern would be nitrogen oxides and carbon monoxide; however, the level of emissions are not considered to be significant.

D. Emission Scenarios and Assumptions

1. Methodology and Assumptions

Uncertainties cloud many aspects of OCS development. The mix of oil and gas; where and when it will be found, and in what quantities; the means of extraction and transport to shore; where and how it will be processed; and finally, how long a tract will be productive, are all predictable only within broad limits. In addition, there are major differences in the design and operating practices of the major oil companies, and characteristics unique to each zone may prescribe different development and operating techniques.

The assumptions and calculations presented in this study are based on the best information and the most accurate predictions available concerning resources and development. However, because of the many uncertainties mentioned above, simplifying assumptions have been made. This section attempts to summarize many of these simplifying assumptions.

Annual, daily, and hourly emissions are estimated. The hourly emissions present the magnitude of maximum emissions expected should all conceivable Lease Sale No. 53 OCS operations occur simultaneously. The daily values are included to show an estimate of emissions that may be generated during a day when a number of operations occur. Some sources, such as tankers, may have high hourly or daily emission rates, yet these emissions occur only intermittently. The annual estimates reflect this and give an accurate perspective of the emissions.

a. Exploratory and Delineation Drilling

The major sources of emissions associated with exploratory and delineation drilling activities are discussed in Section V.B.1. This study assumes that exploratory and delineation drilling in each zone would be done from mobile drilling rigs, such as semisubmersible rigs, jackup rigs, or drill ships. Therefore, emissions associated with the towing or installation of the drilling rigs would be negligible. The major emission sources would be the power generation facilities and the support vessels.

Annual emissions associated with drilling power generation are presented for each zone. These emissions are based on supporting data listed in Appendix A. Estimated daily emissions from drilling operations in each zone are presented in Tables A-5, A-12, A-19, A-26, and A-33 in Appendix A. To develop these emissions, simplifying assumptions were made concerning drilling power generation and the activity of the support vessels.

In estimating the emissions from drilling power generation, a power usage scenario was developed for each type of well drilled in each zone. These scenarios are dependent upon well depth and drilling time estimates provided by the USGS (1978), and assumptions of installed power and usage factors stated in an Energy Resources Company study published in 1977. These power usage scenarios are presented in Appendix A in Tables A-4, A-11, A-18, A-25 and A-32.

All power generation was assumed to be done on board the drilling rig by diesel-fired reciprocating engines. Emission factors for these engines are presented in Table A-1 in Appendix A.

Various assumptions concerning support activity, both onshore and offshore, are made. These include the distance traveled by all support vessels, the home base of these vessels, the frequency of operation, the speed, and fuel consumption of each ship. Assumptions made also include the vehicle miles traveled per day by workers onshore and the operational characteristics of a helicopter used in support. The assumptions made vary from zone to zone, and are presented in the module concerning each specific zone. Emission factors for all support vessels and vehicles are presented in Appendix A in Table A-1.

In estimating the total annual emissions associated with exploratory and delineation drilling activities, the total number of days drilling would occur in each year for each zone was first estimated. The number of active drilling days was based on an estimate of the number of wells to be drilled in a given year and the time it would take to drill one well. The number of active drilling days was then multiplied by the total estimated daily emissions from drilling activities to obtain the total estimated annual emissions.

b. Platform Installation

Assumptions made regarding the emissions associated with platform installation include the number, type, and operational characteristics of vessels and equipment needed for installation and support activity, the types of platforms which would have significant emissions associated with installation, the year each platform would be installed, and the period of time needed to install each platform.

In calculating emissions in each zone, only the platforms designated by the USGS as production or processing platforms (see section V.B.1.b) were considered to have significant quantities of pollutants associated with their installation. Others, designated as floating production systems or offshore storage and loading facilities (see section V.B.1.b) were assumed to be similar to an offshore storage and treatment facility (OS&T) currently proposed for use with Platform Hondo (Exxon, 1979). The Hondo OS&T will be a converted tanker anchored to a single anchor leg mooring system. It will be prefabricated onshore and transported to the point of operation. It is assumed that the same procedure would be used to install the floating production systems and offshore storage and loading facilities. There would be some emissions associated with installing the mooring systems and transporting the vessels to sea; however, compared with emissions associated with other activities they are not expected to be significant.

It was assumed that each platform would be installed the year prior to the year in which production is scheduled to commence on the platform. The USGS has developed a production schedule for each platform (USGS, 1978); installation is expected to take one year (NERBC-RALI, 1977).

Daily emissions associated with the installation of one platform in each zone are presented in the Appendix in Tables A-6, A-13, A-20, A-27, and A-34. To estimate the total daily emissions from platform installation, the total number of production or processing platforms expected to be installed in a

given zone for a specific year (see Table V-3) are multiplied by the applicable daily emissions per platform. To obtain annual emissions associated with platform installation, the total daily emissions, as obtained by the above procedure, are first multiplied by 365, the number of days the installation of one platform is expected to take. Then, recognizing that not all vessels and equipment would operate continuously 24 hours per day and 365 days per year, an overall 60 percent annual usage factor is applied. Annual emissions associated with platform installation for each zone are presented in the following sections.

c. Pipeline Installation

Two types of pipelines are expected to be used for the transport of oil and gas during Lease Sale No. 53 OCS operation. The first is a subsea pipeline to transport the oil or gas to shore. The second would be an overland pipeline to transport the oil or gas to market. Differences in the installation operations of each type of pipeline include the types of equipment and vehicles/vessels needed and the time required for installation.

Emissions for each type of pipeline, while from different sources, and occurring in varying quantities, would follow a common pattern. That is, on a daily or hourly basis, emissions from the installation of a subsea or overland pipeline are expected to be large. On an annual basis, however, emissions from pipeline installation would be relatively small due to the short amount of time installation is expected to require.

The simplifying assumptions made for the analysis of subsea pipeline installation are similar to the assumptions made for the estimation of emissions from platform installation. Vessels and equipment needed, operational characteristics of each, and daily emissions associated with each type of equipment and vessel needed be for subsea pipeline installation in each lease zone are presented in Tables A-7, A-14, A-21, A-28, and A-35 in Appendix A.

Table A-39 in Appendix A lists the operational characteristics and the daily emissions associated with all machinery assumed to be involved with overland pipeline installation. In addition, Table A-40 in Appendix A presents annual emissions associated with overland pipeline installation for each zone and transportation scenario.

Subsea pipelines are assumed to be laid at the rate of one mile per day (Cassel, J.K., 1979) and overland pipeline construction is expected to proceed at the rate of approximately one mile every two and one half days (Woodward-Clyde, 1979b). All pipeline installation is expected to occur the year previous to the start of production in each zone.

To obtain the total annual emissions associated with pipeline installation in a given zone for a specific resource estimate and transportation scenario, the total number of miles of onshore and/or offshore pipeline expected to be laid is found in the USGS resource estimate. By using the installation rates described above, the period of time that would be required for pipeline installation may be determined. This value is then multiplied by the applicable total daily emissions to find total annual emissions associated with pipeline installation which are presented for each zone in the following sections.

d. Development Drilling

As stated in Section V.B.1.b, the major source of emissions associated with development drilling is expected to be the turbines used for generating drilling power. All development wells are expected to be drilled using diesel-fired turbines as a power source. Annual emissions associated with drilling in each zone are presented in the following sections. These emissions are based on detailed support data presented in Appendix A. Emission factors for turbines are presented in Table A-1 in Appendix A. The total power used per well is estimated through the development of power usage scenarios for development drilling in each zone. These scenarios are presented in the Appendix in Tables A-4, A-11, A-18, A-25, and A-32.

For the purposes of estimating the number of wells which would be drilled simultaneously, and thus the maximum estimated daily and hourly emissions from drilling, it was assumed that each production platform and floating production system would finish development drilling within two years of installation. It was also assumed that two wells could be drilled simultaneously on each production platform and floating production system (Kahane, 1979). No drilling is expected to occur on offshore storage and loading facilities.

To obtain values for daily and hourly emissions from drilling in a given zone for the year and resource estimate being considered, the number of platforms on which drilling is expected to occur was estimated. This number was then doubled to account for the assumption of two wells being drilled on each platform simultaneously and then multiplied by the daily or hourly power usage to obtain total power used in an hour or a day. This value is then multiplied by the appropriate emission factor for diesel-fired turbines to find the quantity of pollutants expected to be emitted on a daily or hourly basis from development drilling.

Daily emissions from the drilling of one development well are presented for each zone in Appendix A in Tables A-8, A-15, A-22, A-29, and A-36. To estimate the total annual emissions in a given year for a specific zone and resource estimate, the total number of wells expected to be drilled are taken from the USGS resource estimate study and multiplied by the period of time estimated to be required to drill one well. This gives a value for the number of rig-days drilling is expected to occur. This value is then multiplied by the daily emissions for one well to obtain total annual emissions from development drilling.

e. Production and Processing

Emissions from production and processing are assumed to occur at a steady rate throughout a given year based on the estimated production level for that year.

Power for production was assumed to be generated by diesel-fired turbines installed on the platforms. Emission factors for turbines are presented in Table A-1 in Appendix A. Values for estimated power usage for various activities are presented in Appendix A in Table A-3. All annual and daily emissions presented for production power generation in each zone are based upon the emission factors and power usage described above, and the production levels presented in Table V-1.

Oil processing was assumed to be limited to separation and heat treating. Oil/gas separation was assumed to occur on the platforms in all cases. Heat treating would occur on the platforms in all cases except for BLM Transportation Scenario 1-A in the Santa Maria and Santa Cruz zones. Transportation Scenario 1A assumes that heat treating would occur on shore. The heater treaters were assumed to be fueled by natural gas. It is expected that an average heat input of 15,000 BTUs/barrel of oil would be required (Energy Resource Co., 1977). Annual and daily emissions presented in the next section for oil processing were based upon the above heat requirement, the emission factors for the combustion of natural gas presented in Table A-1 in Appendix A, and the oil production levels shown in Table V-1.

Gas dehydration is expected to require an average heat input of 350,000 BTUs/ 10^6 cubic feet of gas processed (Energy Resources Co., 1977). Natural gas was assumed to be the fuel used. Emission factors for natural gas combustion are presented in Table A-1 in Appendix A. Emissions from gas dehydration are included with emissions from other gas processing operations.

Emissions from other gas processing operations are expected to be dependent upon production levels. Gas processing emissions shown in the annual and daily emission tables for each zone in the next section are based on the gas production levels presented in Table V-1 and the emission factors for gas processing that are given in Table A-1 of Appendix A. It should be noted that the emission factors used to estimate gas processing emissions are based on the most recent average operational data available. It is recognized, however, that emission reduction measures other than the assumed sulfur recovery system may be required on offshore plants to comply with proposed DOI regulations and that BACT may be required by local or state regulatory agencies for any onshore unit. However, the DOI regulations have not yet been promulgated and BACT has not been completely defined for a gas processing plant. The absence of the above regulatory statutes and the lack of emissions data for a controlled gas processing plant has necessitated the use of the most recent operational data.

The evaporative emissions presented in the next section for each zone are also based upon the production level. The emission factors for evaporative emissions are presented in Appendix A in Table A-1. In the absence of fugitive emissions data directly applied to offshore production operations, refinery emission factors have been applied. For a number of reasons, these factors may overestimate fugitive hydrocarbon emissions from offshore operations (Burklin, et al, 1976; Energy Resources Co., 1977); however, they are the only appropriate emission factors currently available. In estimating evaporative emissions from pipeline valves and flanges, it was assumed that the emission factor given in Table A-1 of the Appendix would be reduced by 75 percent to account for the fact that the pipeline is under water (Leach, 1975).

Equations developed by the American Petroleum Institute (API) and presented in AP-42 (EPA, 1977) are used to estimate the quantities of emissions from the onshore storage tanks predicted in Transportation Scenario 1A for the Santa Cruz and Santa Maria zones. These equations and other storage tank assumptions are presented in Table A-41 in Appendix A.

The storage tanks are assumed to be of the floating roof type and equipped with secondary seals. The use of floating roofs with double seals is assumed to represent the Best Available Control Technology (BACT) for storage tanks. In 1976, tests conducted by the Chicago Bridge and Iron Company (CBI) indicated

emissions could be reduced to about 0 to 15 percent of the original API formula through the use of secondary seals. In 1977, while working on the SOHIO West Coast terminal project, the South Coast Air Quality Management District (SCAQMD) and the California Air Resources Board (CARB) utilized 25 percent of the original API formulae to estimate standing and withdrawal emissions from floating roof tanks with secondary seals, to compensate for corrections or deviations from the CBI testing program. Standing and withdrawal losses for this project have been calculated assuming 25 percent of the API formulae.

f. Production and Development Support Activity

Annual emissions associated with production and development support activity presented for each zone in the following sections are based upon the daily emissions presented in Appendix A: Tables A-9, A-16, A-23, A-30, and A-37 for the development phase, and A-10, A-17, A-24, A-31, A-38 for the production phase. Daily development support emissions are given on a per platform basis, and daily production support emissions are based on a specified number of platforms.

It should be noted that, in most cases, drilling would not occur on all platforms simultaneously, nor would drilling occur continuously on any one platform. It could take several years to build all the platforms needed within a zone. The number of platforms required also could vary, depending upon the amount of oil and gas to be recovered. To account for these variables and uncertainties in the actual amount of support activity required, simplified assumptions were made about the number of drilling platforms, the length of time drilling occurs, and possible economies of scale that could exist.

g. Transport of Oil and Gas

In transporting oil or gas by pipeline, the two major emissions associated with pipeline operation would be 1) exhaust emissions from engines producing the power required to compress and pump the recovered gas to shore or to pump the oil produced ashore; and 2) evaporative losses from valves, flanges and seals in the pipeline, pumps and ancillary equipment. Many of these sources are closely allied with oil and gas production and processing. Therefore, the emissions have been reported under the broader headings of production power generation, oil processing, gas processing, evaporative losses and oil pumping. In general the sulfur and nitrogen oxide emissions produced from power generation for pipeline oil or gas transport may account for up to 20 percent of the total project emissions. Evaporative losses related to the operation of pipelines may comprise approximately five percent of the annual hydrocarbon emissions from the entire project.

For the transportation plans in which tankers or barges are used to transport the oil, several operations would occur, regardless of ship size, which would produce significant emissions. As described in previous sections, these common operations include:

1) loading at the offshore facility without the use of vapor balance or vapor recovery systems, which results in substantial uncontrolled emissions of hydrocarbons;

2) operating engines and pumps, which results in exhaust gas emissions from the combustion of residual oil or diesel fuel;

3) breathing within the cargo tanks, which results in a release of hydrocarbons;

4) ballasting tankers without segregated ballast capacity, which results in significant onshore hydrocarbon emissions.

The number and frequency of tanker visits to the production sites have been calculated based upon information provided by the Bureau of Land Management on the sizes of ships to be used, the expected daily production level for the three resource recovery estimates, and the storage capacity of each OS&T facility. The number of ship visits required as well as the ship turnaround times have also been estimated based on information supplied by the Bureau of Land Management. These data are summarized in Tables A-43, A-47, A-48 and A-49 in Appendix A. Once emissions on a per visit basis have been calculated and the duration of each operation of a ship has been estimated, a 24-hour segment can be selected to determine maximum daily emissions. Likewise, the annual emissions can be calculated by multiplying per visit emissions by the number of visits and number of ships required.

2. Scenarios

a. Eel River

i. Total Annual Emissions

a) Offshore Emissions

Annual emissions associated with proposed Lease Sale No. 53 OCS activity in the Eel River zone are presented in Tables V-12 through V-16 by pollutant, activity, year and transportation scenario for the mean resource estimate.

As shown in Tables V-12 through V-16 for the USGS mean resource estimate, exploratory and delineation drilling would occur during the first four years of Lease Sale No. 53 OCS activity. The emissions from these operations would be small in comparison to other phases of Lease Sale No. 53 OCS activity in this zone.

According to the USGS mean resource estimate, development would begin in 1985 with the installation of one platform and the laying of thirteen miles of subsea pipeline and five miles of onshore pipeline. Because of the emissions associated with these various activities, 1985 would be the peak emission year for nitrogen oxides (NO_x) and total suspended particulates (TSP). Also, high levels of carbon monoxide (CO) would be emitted during that year.

Production is scheduled to begin in 1986 (USGS, 1978). The Eel River zone is expected to produce only natural gas, with expected peak production years in 1987 and 1988, according to the mean resource estimate.

The peak emission year for hydrocarbons (HC), sulfur oxides (SO_x), carbon monoxide (CO), and hydrogen sulfide (H_2S) would occur in 1987. The reason for the high emission levels is a combination of the peak production and the development drilling that would be expected to occur that year. The high production level would generate large quantities of hydrocarbons, sulfur oxides and hydrogen sulfide from gas processing, large amounts of all pollutants from power

generation, and large quantities of evaporative hydrocarbon losses. Lesser, yet still significant, amounts of emissions would be generated by development drilling and the transport of supplies and crews necessary to support the drilling operation. It is assumed these support vessels would originate in the Humboldt Bay. The majority of emissions associated with the support vessels would be distributed in the area between Humboldt Bay and the Eel River lease tract.

b) Transportation Emissions

As was stated in Section V.D.1 all gas is expected to be transported to shore via pipeline. The pollutants associated with pipeline transport have been incorporated with production power generation and evaporative hydrocarbon emissions. As this zone is expected to produce only gas, these would be the only emissions associated with transportation.

c) Onshore Emissions

Should BLM Transportation Scenario 1-A be adopted, a gas processing plant would be located onshore approximately four miles inland. The plant would be a significant source of hydrocarbons, sulfur oxides, hydrogen sulfide and nitrogen oxides.

Included in miscellaneous emissions would be those from workers' vehicles and from a helicopter used in support. The major pollutant emitted from the vehicles and the helicopter would be carbon monoxide.

ii. Maximum Hourly Emissions

Maximum hourly emissions for all pollutants, based on the peak production year of 1987, are presented in Table V-17 by the activity which generates the emissions. In addition, Table V-18 presents emissions for oxides of nitrogen, carbon monoxide, and total suspended particulates based on activities in 1985, a year in which a high level of development activity would occur.

Pollutants associated with development in 1985 have been included since the peak emission year for nitrogen oxides, carbon monoxide, and total suspended particulates would occur during this year (two years before the peak production year).

iii. Maximum Daily Emissions

Tables V-17 and V-18 also present maximum daily emissions for all pollutants in the peak production year (1987) and nitrogen oxides, carbon monoxide and total suspended particulates in 1985, respectively, based on the mean resource estimate. The daily emissions are included because some sources, such as support vessels, may emit relatively high quantities of pollutants on an hourly basis, but would not operate continuously during the day. The daily emissions present a more accurate perspective on intermittent emissions.

iv. Comparison with Regional Emission Inventory

The 1976 emission inventory for Humboldt County is presented in Table V-19. The Humboldt County inventory is used for a comparison with the estimated annual emissions associated with proposed Lease Sale No. 53 OCS activity in

Table V-12. ANNUAL HYDROCARBON EMISSIONS ASSOCIATED WITH LEASE SALE NO. 53 OCS OIL AND GAS DEVELOPMENT - EEL RIVER ZONE (MEAN RESOURCE ESTIMATE)

(tons/year)

	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1995	2000	2005
OFFSHORE OPERATIONS COMMON TO ALL SCENARIOS													
Exploratory/Delineation Drilling	0.3	1	1	0.3	--	--	--	--	--	--	--	--	--
Platform Installation[2]	--	--	--	--	23	--	--	--	--	--	--	--	--
Pipeline Installation (13 days)[3]	--	--	--	--	2	--	--	--	--	--	--	--	-
Development Drilling[4]	--	--	--	--	--	0.4	0.8	--	--	--	--	--	--
Supportive Activity[5]	0.2	1	0.8	0.2	2	2	2	1	1	1	1	1	1
Production Power Generation[6]	--	--	--	--	--	16	29	29	29	29	13	5	2
Evaporative Losses[7]	--	--	--	--	--	252	448	448	446	446	203	76	30
(Subtotal - Emissions from Common Offshore Operations)	0.5	2	2	0.5	27	270	480	478	476	476	217	82	33
A. SCENARIOS 1 2, AND 3													
Onshore Emissions													
Pipeline Installation[8]	--	--	--	--	0.3	--	--	--	--	--	--	--	--
Miscellaneous[9]	0.1	0.5	0.4	0.1	1	1	2	0.7	0.7	0.7	0.7	0.7	0.7
Offshore Emissions													
Gas Processing[10]	--	--	--	--	--	1081	1920	1920	1913	1913	870	326	127
Subtotal	0.1	0.5	0.4	0.1	1	1082	1922	1921	1914	1914	871	327	128
TOTAL (Scenarios 1, 2, and 3)	0.6	3	2	0.6	28	1352	2402	2399	2390	2390	1088	409	161
B. SCENARIO 1A													
Onshore Emissions													
Pipeline Installation[8]	--	--	--	--	0.3	--	--	--	--	--	--	--	--
Miscellaneous[9]	0.1	0.5	0.4	0.1	1	1	2	0.7	0.7	0.7	0.7	0.7	0.7
Gas Processing[10]	--	--	--	--	--	1081	1920	1920	1913	1913	870	326	127
Subtotal	0.1	0.5	0.4	0.1	1.3	1082	1922	1921	1914	1914	871	327	128
TOTAL (Scenario 1A)	0.6	3	2	0.6	28	1352	2402	2399	2390	2390	1088	409	161

Table V-12 (continued)

1. Based on number of wells expected to be drilled as presented in Table V-2 and emissions per day per well drilled as presented in Table A-5 in Appendix A.

2. Based on number of platforms expected to be installed as presented in Table V-3, and emissions per day per platform installed as presented in Table A-6 in Appendix A.

3. Based on 13 miles of pipeline expected to be installed as presented in Table V-4 and emissions per day for subsea pipeline installation as presented in Table A-7 in Appendix A.

4. Based on number of wells expected to be drilled as presented in Table V-2 and emissions per day per well drilled as presented in Table A-8 in Appendix A.

5. Based on emissions presented in Tables A-5, A-6, A-7, A-9, and A-10 in Appendix A.

6. Based on emission factors for diesel fired turbines presented in the Appendix in Table A-1, power usage factors presented in Table A-3 in Appendix A and production level presented in Table V-1.

7. Based on evaporative emission factors presented in Table A-1 in Appendix A and production level presented in Table V-1.

8. See Table A-40 in the Appendix A for annual emissions from overland pipeline installation.

9. Includes workers' vehicles and helicopter. Based on emissions presented in Tables A-5, A-6, A-7, A-9 and A-10 in Appendix A.

10. Based on emission factors for gas processing presented in Table A-1 in Appendix A and production level presented in Table V-1.

Table V-13. ANNUAL NITROGEN OXIDE EMISSIONS ASSOCIATED WITH LEASE SALE NO. 53 OCS OIL AND GAS DEVELOPMENT - EEL RIVER ZONE (MEAN RESOURCE ESTIMATE)

(tons/year)

	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1995	2000	2005
OFFSHORE OPERATIONS COMMON TO ALL SCENARIOS													
Exploratory/Delineation Drilling[1]	8	39	31	8	--	--	--	--	--	--	--	--	--
Platform Installation[2]	--	--	--	--	631	--	--	--	--	--	--	--	--
Pipeline Installation (13 days)[3]	--	--	--	--	44	--	--	--	--	--	--	--	--
Development Drilling[4]	--	--	--	--	--	5	10	--	--	--	--	--	--
Supportive Activity[5]	5	23	18	5	39	43	61	31	31	31	31	31	31
Production Power Generation[6]	--	--	--	--	--	121	214	214	213	213	97	36	14
(Subtotal-Emissions from Common Offshore Operations)	13	62	49	13	714	169	290	245	244	244	128	67	45
A. SCENARIOS 1, 2 AND 3:													
Onshore Emissions													
Pipeline Construction[7]	--	--	--	--	4	--	--	--	--	--	--	--	--
Miscellaneous[8]	Neg.	1	1	Neg.	3	2	3	1	1	1	1	1	1
Offshore Emissions													
Gas Processing[9]	--	--	--	--	--	51	91	91	91	91	41	16	6
Subtotal	--	1	1	--	7	53	94	92	92	92	42	17	7
TOTAL (Scenarios 1, 2 and 3)	13	63	50	13	721	222	379	337	336	336	170	84	52
B. SCENARIO 1A:													
Onshore Emissions													
Pipeline Construction[7]	--	--	--	--	4	--	--	--	--	--	--	--	--
Miscellaneous[8]	Neg.	1	1	Neg.	3	2	3	1	1	1	1	1	1
Gas Processing[9]	--	--	--	--	--	51	91	91	91	91	41	16	6
Subtotal	--	1	1	--	7	53	94	92	92	92	42	17	7
TOTAL (Scenario 1A)	13	63	50	13	721	222	379	337	336	336	170	84	52

Table V-13 (continued)

1. Based on number of wells expected to be drilled as presented in Table V-2 and emissions per day per well drilled as presented in Table A-5 in Appendix A.

2. Based on number of platforms expected to be installed as presented in Table V-3, and emissions per day per platform installed as presented in Table A-6 in Appendix A.

3. Based on 13 miles of pipeline expected to be installed as presented in Table V-4 and emissions per day for subsea pipeline installation as presented in Table A-7 in Appendix A.

4. Based on number of wells expected to be drilled as presented in Table V-2 and emissions per day per well drilled as presented in Table A-8 in Appendix A.

5. Based on emissions presented in Tables A-5, A-6, A-7, A-9, and A-10 in Appendix A.

6. Based on emission factors for diesel fired turbines presented in Appendix A in Table A-1, power usage factors presented in Table A-3 in Appendix A and production level presented in Table V-1.

7. See Table A-40 in Appendix A for annual emissions from overland pipeline installation.

8. Includes workers' vehicles and helicopter. Based on emissions presented in Tables A-5, A-6, A-7, A-9, and A-10 in Appendix A.

9. Based on emission factors for gas processing presented in Table A-1 in Appendix A and production level presented in Table V-1.

Table V-14. ANNUAL SULFUR OXIDE EMISSIONS ASSOCIATED WITH LEASE SALE NO. 53 OCS OIL AND GAS DEVELOPMENT - EEL RIVER ZONE (MEAN RESOURCE ESTIMATE)

(tons/year)

	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1995	2000	2005
OFFSHORE OPERATIONS COMMON TO ALL SCENARIOS													
Exploratory/Delineation Drilling[1]	0.5	2.6	2	0.5	--	--	--	--	--	--	--	--	--
Platform Installation[2]	--	--	--	--	42	--	--	--	--	--	--	--	--
Pipeline Installation (13 days)[3]	--	--	--	--	3	--	--	--	--	--	--	--	--
Development Drilling[4]	--	--	--	--	--	3	5	--	--	--	--	--	--
Supportive Activity[5]	0.5	3.0	2.4	0.5	3	5	6	4	4	4	4	4	4
Production Power Generation[6]	--	--	--	--	--	93	165	165	164	164	75	28	11
(Subtotal - Emissions from Common Offshore Operations)	1	6	4	1	48	101	176	169	168	168	79	32	15
A. SCENARIOS 1 2, AND 3													
Onshore Emissions													
Pipeline Installation[7]	--	--	--	--	0.3	--	--	--	--	--	--	--	--
Miscellaneous[8]	Neg.	0.2	0.2	Neg.	0.3	0.3	0.4	0.2	0.2	0.2	0.2	0.2	0.2
Offshore Emissions													
Gas Processing[9]	--	--	--	--	--	55	97	97	97	97	44	16	6
Subtotal	--	0.2	0.2	--	0.6	55	97	97	97	97	44	16	6
TOTAL (Scenarios 1, 2, and 3)	1	6	5	1	49	155	273	266	265	265	123	48	21
B. SCENARIO 1A													
Onshore Emissions													
Pipeline Installation[7]	--	--	--	--	0.3	--	--	--	--	--	--	--	--
Miscellaneous[8]	Neg.	0.2	0.2	Neg.	0.3	0.3	0.4	0.2	0.2	0.2	0.2	0.2	0.2
Gas Processing[9]	--	--	--	--	--	55	97	97	97	97	44	16	6
Subtotal	--	0.2	0.2	--	0.6	55	97	97	97	97	44	16	6
TOTAL (Scenario 1A)	1	6	5	1	49	155	273	266	265	265	123	48	21

Table V-14 (continued)

1. Based on number of wells expected to be drilled as presented in Table V-2 and emissions per day per well drilled as presented in Table A-5 in Appendix A.

2. Based on number of platforms expected to be installed as presented in Table V-3, and emissions per day per platform installed as presented in Table A-6 in Appendix A.

3. Based on 13 miles of pipeline expected to be installed as presented in Table V-4 and emissions per day for subsea pipeline installation as presented in Table A-7 in Appendix A.

4. Based on number of wells expected to be drilled as presented in Table V-2 and emissions per day per well drilled as presented in Table A-8 in Appendix A.

5. Based on emissions presented in Tables A-5, A-6, A-7, A-9, and A-10 in Appendix A.

6. Based on emission factors for diesel fired turbines presented in Appendix A in Table A-1, power usage factors presented in Table A-3 in Appendix A and production level presented in Table V-1.

7. See Table A-40 in Appendix A for annual emissions from overland pipeline installation.

8. Includes workers' vehicles and helicopter. Based on emissions presented in Tables A-5, A-6, A-7, A-9, and A-10 in Appendix A.

9. Based on emission factors for gas processing presented in Table A-1 in Appendix A and production level presented in Table V-1.

Table V-15. ANNUAL CARBON MONOXIDE EMISSIONS ASSOCIATED WITH LEASE SALE NO. 53 OCS OIL AND GAS DEVELOPMENT - EEL RIVER ZONE (MEAN RESOURCE ESTIMATE)

(tons/year)

	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1995	2000	2005
OFFSHORE OPERATIONS COMMON TO ALL SCENARIOS													
Exploratory/Delineation Drilling[1]	1	6	5	1	--	--	--	--	--	--	--	--	--
Platform Installation[2]	--	--	--	--	102	--	--	--	--	--	--	--	--
Pipeline Installation (13 days)[3]	--	--	--	--	7	--	--	--	--	--	--	--	--
Development Drilling[4]	--	--	--	--	--	1	2	--	--	--	--	--	--
Supportive Activity[5]	1	3	3	1	6	38	48	34	34	34	34	34	34
Production Power Generation[6]	--	--	--	--	--	38	68	68	67	67	31	11	4
(Subtotal - Emissions from Common Offshore Operations)	2	9	8	2	115	77	118	102	101	101	65	45	38
ALL SCENARIOS													
Onshore Emissions													
Pipeline Installation[7]	--	--	--	--	1	--	--	--	--	--	--	--	--
Miscellaneous[8]	1	6	5	1	19	18	26	12	12	12	12	12	12
Subtotal	1	6	5	1	20	18	26	12	12	12	12	12	12
TOTAL (All Scenarios)	3	15	13	3	135	95	144	114	113	113	77	57	50

Table V-15 (continued)

1. Based on number of wells expected to be drilled as presented in Table V-2 and emissions per day per well drilled as presented in Table A-5 in Appendix A.

2. Based on number of platforms expected to be installed as presented in Table V-3, and emissions per day per platform installed as presented in Table A-6 in Appendix A.

3. Based on 13 miles of pipeline expected to be installed as presented in Table V-4 and emissions per day for subsea pipeline installation as presented in Table A-7 in Appendix A.

4. Based on number of wells expected to be drilled as presented in Table V-2 and emissions per day per well drilled as presented in Table A-8 in Appendix A.

5. Based on emissions presented in Tables A-5, A-6, A-7, A-9, and A-10 in Appendix A.

6. Based on emission factors for diesel fired turbines presented in Appendix A in Table A-1, power usage factors presented in Table A-3 in Appendix A and production level presented in Table V-1.

7. See Table A-40 in Appendix A for annual emissions from overland pipeline installation.

8. Includes workers' vehicles and helicopter. Based on emissions presented in Tables A-5, A-6, A-7, A-9, and A-10 in Appendix A.

Table V-16. ANNUAL TOTAL SUSPENDED PARTICULATE EMISSIONS ASSOCIATED WITH LEASE SALE NO. 53 OCS OIL AND GAS DEVELOPMENT - EEL RIVER ZONE (MEAN RESOURCE ESTIMATE)

(tons/year)

	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1995	2000	2005
OFFSHORE OPERATIONS COMMON TO ALL SCENARIOS													
Exploratory/Delineation Drilling[1]	--	--	--	--	--	--	--	--	--	--	--	--	--
Platform Installation[2]	--	--	--	--	31	--	--	--	--	--	--	--	--
Pipeline Installation (13 days)[3]	--	--	--	--	2	--	--	--	--	--	--	--	--
Development Drilling[4]	--	--	--	--	--	0.5	1	--	--	--	--	--	--
Supportive Activity[5]	0.2	1	1	0.2	2	3	4	2	2	2	2	2	2
Production Power Generation[6]	--	--	--	--	--	16	29	29	29	29	13	5	2
(Subtotal - Emissions from Common Offshore Operations)	0.2	1	1	0.2	35	20	34	31	31	31	15	7	4
ALL SCENARIOS													
Onshore Emissions													
Pipeline Installation[7]		--	--	--	0.2	--	--	--	--	--	--	--	--
Miscellaneous[8]	Neg.	0.2	0.2	Neg.	0.6	0.5	0.7	0.4	0.4	0.4	0.4	0.4	0.4
Subtotal	--	0.2	0.2	--	0.8	0.5	0.7	0.4	0.4	0.4	0.4	0.4	0.4
TOTAL (All Scenarios)	0.2	1	1	0.2	36	20	35	31	31	31	15	7	4

Table V-16 (continued)

1. Based on number of wells expected to be drilled as presented in Table V-2 and emissions per dsy per well drilled as presented in Table A-5 in Appendix A.

2. Based on number of platforms expected to be installed as presented in Table V-3, and emissions per day per platform installed as presented in Table A-6 in Appendix A.

3. Based on 13 miles of pipeline expected to be installed as presented in Table V-4 and emissions per day for subsea pipeline installation as presented in Table A-7 in Appendix A.

4. Based on number of wells expected to be drilled as presented in Table V-2 and emissions per day per well drilled as presented in Table A-8 in Appendix A.

5. Based on emissions presented in Tables A-5, A-6, A-7, A-9, and A-10 in Appendix A.

6. Based on emission factors for diesel fired turbines presented in Appendix A in Table A-1, power usage factors presented in Table A-3 in Appendix A and production level presented in Table V-1.

7. See Table A-40 in Appendix A for annual emissions from overland pipeline installation.

8. Includes worker vehicles and helicopter, based on emissions presented in Tables A-5, A-6, A-7, A-9, and A-10 in Appendix A.

Table V-17. MAXIMUM DAILY AND HOURLY EMISSIONS ASSOCIATED WITH LEASE SALE NO. 53 OCS OIL AND GAS DEVELOPMENT - EEL RIVER ZONE

(MEAN RESOURCE ESTIMATE, PEAK PRODUCTION YEAR - 1987)

	Emissions lbs/day (lbs/hr)					
Source/Activity	HC	NO_x	SO_x	CO	TSP	H_2S
OFFSHORE SOURCES COMMON TO ALL SCENARIOS						
Development Drilling[1]	24(1)	296(12)	156(6)	68(3)	20(0.8)	--
Support Activity[2]	23(4)	990(138)	67(9)	148(21)	44(6)	--
Power Generation[3]	160(7)	1172(49)	902(38)	371(15)	160(7)	--
Evaporative Losses[4]	2455(102.3)	--	--	--	--	--
ONSHORE SOURCES COMMON TO ALL SCENARIOS						
Miscellaneous[5]	28(1.2)	46(1.9)	6(0.3)	432(18)	12(0.5)	--
Subtotal	2690(115)	2504(201)	1131(53)	1019(57)	236(14)	
SCENARIOS 1,2,3						
OFFSHORE SOURCES						
Gas Processing[6]	10,521(438)	501(21)	531(22)	--	--	130(5)
TOTAL (Scenarios 1,2,3)	13,211(554)	3005(222)	1662(75)	1019(57)	236(14)	130(5)
SCENARIO 1A						
ONSHORE SOURCES						
Gas Processing[6]	10,521(438)	501(21)	531(22)	--	--	130(5)
TOTAL (Scenario 1A)	13,211(554)	3005(222)	1662(75)	1019(57)	236(14)	130(5)

Table V-17 (continued)

1. Based on four wells expected to be drilled simultaneously and emissions per day per well drilled presented in Table A-8 of Appendix A.

2. Daily emissions based on Tables A-9 and A-10 presented in Appendix A. Hourly emissions assume two crew boats and one supply boat operating simultaneously and emission factors presented in Table A-1 of Appendix A.

3. Based on emission factors for diesel fired turbines presented in Table A-1 of Appendix A and production level presented in Table V-1 .

4. Based on evaporative emission factors presented in Appendix A in Table A-1 and production level presented in Table V-1.

5. Includes workers' vehicles and helicopter. Based on emissions presented in Tables A-9 and A-10 in Appendix A.

6. Based on emission factors for gas processing presented in Table A-1 of Appendix A and production level presented in Table V-1.

Table V-18. MAXIMUM DAILY AND HOURLY NITROGEN OXIDE, CARBON MONOXIDE AND TOTAL SUSPENDED PARTICULATE EMISSIONS ASSOCIATED WITH LEASE SALE NO. 53 OCS OIL AND GAS DEVELOPMENT - EEL RIVER ZONE

(MEAN RESOURCE ESTIMATE, PEAK EMISSION YEAR - 1985)

	Emissions lbs/day (lbs/hr)		
Source/Activity	NO_x	CO	TSP
OFFSHORE SOURCES COMMON TO ALL SCENARIOS			
Platform Installation	4,939 (240)	809 (39)	244 (12)
Pipeline Installation	7,923 (330)	1,344 (56)	415 (17)
Support Activity	668 (149)	100 (22)	30 (6)
ONSHORE SOURCES COMMON TO ALL SCENARIOS			
Miscellaneous	48 (2)	380 (16)	13 (0.5)
TOTAL	13,578 (721)	2,633 (133)	702 (36)

1. Based on one platform expected to be installed as presented in Table V-3 and emissions per day per platform installed presented in Table A-6 in Appendix A.

2. Based on emissions per day for pipeline installation as presented in Table A-7 in Appendix A.

3. Includes support for all activities expected to occur. Based on Tables A-6 and A-7 in Appendix A.

4. Includes workers' vehicles and helicopter. Based on emissions presented in Tables A-6 and A-7 in Appendix A.

Table V-19. 1976 EMISSIONS FOR HUMBOLDT COUNTY[1]

Source	Emissions - tons/year (% of total emissions)				
	HC[2]	NO_x	SO_x	CO	TSP
Petroleum[3]	1,789(16%)	--	--	--	--
Organic Solvents	1,059(9%)	--	--	--	--
Combustion of Fuels	584(5%)	2,701(3%)	2,044(58%)	2,920(5%)	3,468(39%)
Waste Burning	4,088(35%)	803(10%)	--	25,258(48%)	3,358(38%)
Other Stationary[4]	329(3%)	621(8%)	1,205(35%)	3,833(7%)	1,643(18%)
Mobile[5]	3,723(32%)	3,979(49%)	255(7%)	21,097(4%)	402(5%)
Total	11,572(100%)	8,104(100%)	3,504	53,108(100%)	8,871(100%)

1. Source: California North Coast Air Basin Air Pollution Control Council, Air Pollution Control Plan for the California North Coast Air Basin (1977). Emissions are for 1976. No other data available.
2. Total hydrocarbon emissions.
3. Emissions are from marketing only.
4. Includes industrial emissions and miscellaneous area sources.
5. Includes all on road vehicles, aircraft, ships and railroad.

Table V-20. COMPARISON OF EMISSIONS ASSOCIATED WITH LEASE SALE NO. 53 ACTIVITIES IN THE EEL RIVER ZONE WITH COMBINED REGIONAL EMISSION INVENTORY FOR HUMBOLDT COUNTY

Pollutant	Peak Emission Year	TONS PER YEAR[1] (PERCENTAGE OF EMISSIONS ASSOCIATED WITH LEASE SALE NO. 53 ACTIVITIES TO REGIONAL EMISSION INVENTORY)[2]			
		Transportation Scenario 1	Transportation Scenario 1-A	Transportation Scenario 2	Transportation Scenario 3
Total Hydrocarbons	1987	2,402(21%)	2,402(21%)	2,402(21%)	2,402(21%)
Nitrogen Oxides	1985	721(9%)	721(9%)	721(9%)	721 (9%)
Sulfur Oxides	1987	273(8%)	273(8%)	273(8%)	273(8%)
Carbon Monoxide	1987	144(0.2%)	144(0.2%)	144(0.2%)	144(0.2%)
Total Suspended Particulate	1985	35(0.4%)	35(0.4%)	35(0.4%)	35(0.4%)

1. Based on the USGS mean resource estimate.
2. Emissions associated with Lease Sale No. 53 OCS activity in the Eel River Zone have been compared to 1976 onshore emissions for Humboldt County. Emissions for Humboldt County have been obtained from the Air Pollution Control Plan for the California North Coast Air Basin (California North Coast Air Basin Air Pollution Control Council, 1977).

the Eel River zone because of its proximity to the zone as well as the predominant wind directions. Though it is estimated that 1985 and 1987 would be the peak emission years in the Eel River zone, the only county emission inventory available for comparison is for 1976.

As may be seen in Table V-19, a large portion of the total annual emissions in Humboldt County occur from waste burning. In addition, a substantial amount of emissions are from mobile sources, primarily automobiles. The only petroleum related emissions in the county are from gasoline distribution and marketing.

A comparison of the 1976 emissions inventory with the emissions associated with Lease Sale No. 53 OCS activity in the Eel River zone based on the mean resource estimate is presented in Table V-20. As shown in Table V-20, among the five pollutants of concern, hydrocarbons represent the largest percent of Lease No. 53 pollutant emissions relative to regional onshore emissions. The level of hydrocarbons from Lease Sale No. 53 OCS activities would be approximately 21 percent of the amount of hydrocarbons emitted onshore from other activities. The amount of sulfur and nitrogen oxides from Lease Sale No. 53 OCS activities would be approximately 8 to 9 percent of total regional onshore sulfur and nitrogen oxide emissions. Carbon monoxide and total suspended particulate emissions associated with Lease Sale No. 53 OCS activities would be negligible when compared to regional onshore emissions.

It should be noted that the estimated peak emissions associated with proposed Lease Sale No. 53 OCS activity in the Eel River zone are used for comparison. The level of emissions, and therefore the comparative percentage, would be lower in other years of Lease Sale No. 53 activity in the Eel River zone.

b. Point Arena

i. Total Annual Emissions

a) Offshore Emissions

Exploratory and delineation drilling would occur during the first four years after the lease sale, 1981 through 1984. As shown in Tables V-21 - V-25, emissions associated with exploration activities in these years would be low.

Large scale development would be expected to begin in 1985 with the installation of a platform, 13 miles of pipeline from the platform to shore and approximately 33 additional miles of pipeline on shore to connect to existing utility pipelines. The tugboats, lay barges, bury barges and other support vessels would produce substantial quantities of nitrogen oxides from combustion of diesel fuel. Lesser quantities of sulfur oxides, carbon monoxide, and particulate matter would also be generated as combustion products.

Production would begin in 1986 and would reach the maximum level in 1989 followed by a gradual decline in production activities in subsequent years. The major pollutants expected to be emitted offshore are sulfur oxides and nitrogen oxides from power generation, hydrocarbons from evaporation losses, and sulfur oxides, hydrogen sulfide and hydrocarbons from gas processing. (Under all Transportation Scenarios except 1A, the gas processing plant would be located offshore.)

Table V-21. ANNUAL HYDROCARBON EMISSIONS ASSOCIATED WITH LEASE SALE NO. 53 OCS OIL AND GAS DEVELOPMENT -- POINT ARENA ZONE (MEAN RESOURCE ESTIMATE)

(tons/year)

	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1995	2000	2005
OFFSHORE OPERATIONS COMMON TO ALL SCENARIOS													
Exploratory/Delineation Drilling[1]	0.4	2	2	1	--	--	--	--	--	--	--	--	--
Platform Installation[2]	--	--	--	--	23	--	--	--	--	--	--	--	--
Pipeline Installation (13 days)[3]	--	--	--	--	1	--	--	--	--	--	--	--	--
Development Drilling[4]	--	--	--	--	--	1	2	2	1	--	--	--	--
Supportive Activity[5]	1	6	7	2	8	11	16	21	15	13	13	13	13
Production Power Generation[6]	--	--	--	--	--	7	21	32	36	30	13	6	2
Oil Processing[7]	--	--	--	--	--	Neg.	0.5	1	1	0.7	0.3	0.2	0.
Evaporative Losses[8]	--	--	--	--	--	83	235	362	410	345	149	64	27
(Subtotal - Emissions from Common Offshore Operations)	1	8	9	3	32	166	275	418	463	389	175	83	42
A. SCENARIOS 1 AND 2:													
Onshore Emissions													
Pipeline Installation[9]	--	--	--	--	2	--	--	--	--	--	--	--	--
Miscellaneous[10]	0.1	1	1	0.1	1	1	2	3	2	1	1	1	1
Tankers In Port[11]	--	--	--	--	--	7	20	31	35	29	13	6	2
Offshore Emissions													
Gas Processing[12]	--	--	--	--	--	368	1050	1617	1817	1533	663	284	126
Tankers at OS&T[13]	--	--	--	--	--	69	199	303	343	293	126	54	22
Tankers In Transit[14]	--	--	--	--	--	12	36	54	61	52	23	10	4
Subtotal	0.1	1	1	0.1	3	457	1307	2008	2258	1908	826	355	155
TOTAL (Scenarios 1 and 2)	2	9	10	3	35	623	1582	2426	2721	2297	1001	438	197

Table V-21 (continued)

	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1995	2000	2005
B. SCENARIO 1A:													
Onshore Emissions													
Pipeline Installation[9]	--	--	--	--	2	--	--	--	--	--	--	--	--
Gas Processing[12]	--	--	--	--	--	368	1050	1617	1817	1533	663	284	126
Miscellaneous[10]	0.1	1	1	0.1	1	1	2	3	2	1	1	1	1
Tankers In Port[11]	--	--	--	--	--	7	20	31	35	29	13	6	2
Offshore Emissions													
Pipeline Installation (9 days)[3]	--	--	--	--	2	--	--	--	--	--	--	--	--
Tankers at OSRT[13]	--	--	--	--	--	69	199	303	343	293	126	54	22
Tankers In Transit[14]	--	--	--	--	--	12	36	54	61	52	23	10	4
Subtotal	0.1	1	1	0.1	5	457	1307	2008	2258	1908	826	355	155
TOTAL (Scenario 1A)	2	9	10	3	35	623	1582	2426	2721	2297	1001	438	197
C. SCENARIO 3:													
Onshore Emissions													
Pipeline Installation[9]	--	--	--	--	2	--	--	--	--	--	--	--	--
Gas Processing[12]	--	--	--	--	--	368	1050	1617	1817	1533	663	284	126
Miscellaneous[10]	0.1	1	1	0.1	1	1	2	3	2	1	1	1	1
Offshore Emissions													
Tankers at OSRT[15]	--	--	--	--	--	68	197	306	340	286	122	54	27
Tankers In Transit[16]	--	--	--	--	--	Neg.	0.2	0.3	0.3	0.2	0.1	Neg.	Neg
Subtotal	0.1	1	1	0.1	3	437	1249	1926	2159	1819	786	339	154
TOTAL (Scenario 3)	2	9	10	3	35	603	1524	2344	2622	2208	961	422	196

Table V-21 (continued)

1. Based on number of wells expected to be drilled as presented in Table V-2 and emissions per day per well drilled as presented in Table A-12 in Appendix A.

2. Based on number of platforms expected to be installed as presented in Table V-3, and emissions per day per platform installed as presented in Table A-13 in Appendix A.

3. Based on miles of pipeline expected to be installed as presented in Table V-4 and emissions per day for subsea pipeline installation as presented in Table A-14 in Appendix A.

4. Based on number of wells expected to be drilled as presented in Table V-2 and emissions per day per well drilled as presented in Table V-15 in Appendix A.

5. Based on emissions presented in Tables A-12, A-13, A-14, A-16, and A-17 in Appendix A.

6. Based on emission factors for diesel fired turbines presented in Appendix A in Table A-1, power usage factors presented in Table A-3 in Appendix A and production level presented in Table V-1.

7. Based on emission factors for natural gas combustion presented in Table A-1 in Appendix A, an average heat requirement of 15,000 BTU/bbl (Energy Resources Co., 1977) and production level presented in Table V-1.

8. Based on evaporative emission factors presented in Table A-1 in Appendix A and production level presented in Table V-1.

9. See Table A-10 in Appendix A for annual emissions associated with overland pipeline installation.

10. Includes workers' vehicles and helicopter. Based on emissions presented in Tables A-12, A-13, A-14, A-16 and A-17 in Appendix A.

11. Emissions would occur while the tanker or barge is docked at San Francisco. Based upon per visit emissions in Table A-50 in Appendix A and expected number of voyages required as presented in Table A-47 in Appendix A.

12. Based on emission factors for gas processing presented in Table A-1 in Appendix A and production level presented in Table V-1.

13. Emissions would occur while the tanker or barge is docked at the OS&T. Based upon per visit emissions given in Table A-50 in Appendix A and the expected number of voyages required as presented in Table A-47 in Appendix A.

14. Emissions would occur while the tanker or barge is en route between the OS&T and the dock in San Francisco. Based upon per visit emissions given in Table A-50 in Appendix A and the expected number of voyages required as presented in Table A-47 in Appendix A.

Table V-21 (continued)

15. Emissions would occur while the tanker is docked at the OS&T. They are based upon per visit emissions given in Table A-53 in Appendix A and the expected number of voyages required as presented in Table A-47 in Appendix A.

16. Emissions would occur while the tanker is travelling in waters adjacent to Mendocino County. Based upon per visit emissions given in Table A-53 and the expected number of voyages required as presented in Table A-47 in Appendix A.

Table V-22. ANNUAL NITROGEN OXIDE EMISSIONS ASSOCIATED WITH LEASE SALE NO. 53 OCS OIL AND GAS DEVELOPMENT - POINT ARENA ZONE (MEAN RESOURCE ESTIMATE)

(tons/year)

	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1995	2000	2005
OFFSHORE OPERATIONS COMMON TO ALL SCENARIOS													
Exploratory/Delineation Drilling[1]	11	47	55	17	--	--	--	--	--	--	--	--	--
Platform Installation[2]	--	--	--	--	631	--	--	--	--	--	--	--	--
Pipeline Installation(13 days)[3]	--	--	--	--	38	--	--	--	--	--	--	--	--
Development Drilling[4]	--	--	--	--	--	11	23	23	14	--	--	--	--
Supportive Activity[5]	53	232	274	84	335	476	688	899	838	527	527	527	527
Production Power Generation[6]	--	--	--	--	--	58	168	258	291	245	106	45	20
Oil Processing[7]	--	--	--	--	--	2	7	11	12	10	4	2	1
(Subtotal - Emissions from Common Offshore Operations)	64	279	329	101	1004	547	886	1191	1155	782	637	574	548
A. SCENARIOS 1 AND 2:													
Onshore Emissions													
Pipeline Installation[8]	--	--	--	--	29	--	--	--	--	--	--	--	--
Miscellaneous[9]	0.2	1	1	0.1	2	2	4	4	4	2	2	2	2
Tankers in Port[10]	--	--	--	--	--	0.8	2	4	4	3	2	0.6	0.3
Offshore Emissions													
Gas Processing[11]	--	--	--	--	--	18	50	77	87	73	32	14	6
Tankers at OS&T[12]	--	--	--	--	--	0.6	2	2	3	2	1	0.4	0.2
Tankers in Transit[13]						10	29	44	50	42	18	8	3
Subtotal	0.2	1	1	0.1	31	31	87	131	148	123	54	25	12
TOTAL (Scenarios 1 and 2)	64	280	330	101	1035	578	73	1322	1303	905	92	599	560

Table V-22 (continued)

	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1995	2000	2005
B. SCENARIO 1A:													
Onshore Emissions													
Pipeline Construction[8]	--	--	--	--	31	--	--	--	--	--	--	--	--
Gas Processing[11]	--	--	--	--	--	18	50	77	87	73	32	14	6
Miscellaneous[9]	0.2	1	1	0.1	2	2	4	4	4	2	2	2	2
Tankers In Port[10]	--	--	--	--	--	0.8	2	4	4	3	2	0.6	0.3
Offshore Emissions													
Additional Subsea Pipeline Installation[3]	--	--	--	--	28	--	--	--	--	--	--	--	--
Additional Support Activity[5]	--	--	--	--	13	--	--	--	--	--	--	--	--
Tankers at OS&T[12]	--	--	--	--	--	0.6	2	2	3	2	1.0	0.4	0.2
Tankers In Transit[13]	--	-	--	--	--	10	29	44	50	42	18	8	3
Subtotal	0.2	1	1	0.1	74	31	87	131	148	123	54	25	12
TOTAL (Scenario 1A)	64	280	330	101	1078	578	973	1322	1303	905	692	599	560
C. SCENARIO 3:													
Onshore Emissions													
Pipeline Installation[8]	--	--	--	29	--	--	--	--	--	--	--	--	--
Miscellaneous[9]	0.2	1	1	0.1	2	2	4	4	4	2	2	2	2
Offshore Emissions													
Gas Processing[11]	--	--	--	--	--	18	50	77	87	73	32	14	6
Tankers at OS&T[14]	--	--	--	--	--	1	3	5	6	5	2	0.9	0.5
Tankers In Transit[15]	--	--	--	--	--	0.9	3	4	5	4	2	0.7	0.4
Subtotal	0.2	1	1	29	2	22	60	90	102	84	38	17	9
TOTAL (Scenario 3)	64	280	330	130	1006	569	946	1281	1257	866	675	592	557

Table V-22 (continued)

1. Based on number of wells expected to be drilled as presented in Table V-2 and emissions per day per well drilled as presented in Table A-12 in Appendix A.

2. Based on number of platforms expected to be installed as presented in Table V-3, and emissions per day per platform installed as presented in Table A-13 in Appendix A.

3. Based on miles of pipeline expected to be installed as presented in Table V-4 and emissions per day for subsea pipeline installation as presented in Table A-14 in Appendix A.

4. Based on number of wells expected to be drilled as presented in Table V-2 and emissions per day per well drilled as presented in Table A-15 in Appendix A.

5. Based on emissions presented in Tables A-12, A-13, A-14, A-16, and A-17 in Appendix A.

6. Based on emission factors for diesel fired turbines presented in Appendix A in Table A-1, power usage factors presented in Table A-3 in Appendix A and production level presented in Table V-1.

7. Based on emission factors for natural gas combustion presented in Table A-1 in Appendix A, an average heat requirement of 15,000 Btu/bbl (Energy Resources Co., 1977) and production level presented in Table V-1.

8. See Table A-40 in Appendix A for annual emissions associated with overland pipeline construction.

9. Includes workers' vehicles and helicopter. Based on emissions presented in Tables A-12, A-13, A-14, A-16, and A-17 in Appendix A.

10. Emissions would occur while the tanker or barge is docked at San Francisco. Based upon per visit emissions given in Table A-50 in Appendix A and expected number of voyages required as presented in Table A-47 in Appendix A.

11. Based on emission factors for gas processing presented in Table A-1 in Appendix A and production level presented in Table V-1.

12. Emissions would occur while the tanker or barge is docked at the OS&T. Based upon per visit emissions given in Table A-50 in Appendix A and expected number of voyages required as presented in Table A-47 in Appendix A.

13. Emissions would occur while the tanker or barge is en route between the OS&T and the dock in San Francisco. Based upon per visit emissions given in Table A-50 in Appendix A and the expected number of voyages required as presented in Table A-47 in Appendix A.

14. Emissions would occur while the tanker or barge is docked at the OS&T. Based upon per visit emissions given in Table A-53 in Appendix A and the expected number of voyages required as presented in Table A-47 in Appendix A.

15. Emissions would occur while the tanker is traveling in waters adjacent to Mendocino County. Based upon per visit emissions given in Table A-53 in Appendix A and the expected number of voyages required as presented in Table A-47 in Appendix A.

Table V-23. ANNUAL SULFUR OXIDE EMISSIONS ASSOCIATED WITH LEASE SALE NO. 53 OCS OIL AND GAS DEVELOPMENT - POINT ARENA ZONE (MEAN RESOURCE ESTIMATE)

(tons/year)

	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1995	2000	2005
OFFSHORE OPERATIONS COMMON TO ALL SCENARIOS													
Exploratory/Delineation Drilling[1]	1	3	4	1	--	--	--	--	--	--	--	--	--
Platform Installation[2]	--	--	--	--	42	--	--	--	--	--	--	--	--
Pipeline Installation(13 days)[3]	--	--	--	--	3	--	--	--	--	--	--	--	--
Development Drilling[4]	--	--	--	--	--	6	12	12	7	--	--	--	--
Supportive Activity[5]	4	16	19	6	23	32	47	61	57	36	36	36	36
Production Power Generation[6]	--	--	--	--	--	41	118	181	204	172	74	32	14
(Subtotal - Emissions from Common Offshore Operations)	5	19	23	7	68	79	177	254	268	208	110	68	44
A. SCENARIOS 1 AND 2:													
Onshore Emissions													
Pipeline Construction[7]	--	--	--	--	2	--	--	--	--	--	--	--	--
Miscellaneous[8]	Neg.	0.2	0.2	Neg.	0.2	0.3	0.5	0.5	0.4	0.2	0.2	0.2	0.2
Tankers In Port[9]	--	--	--	--	--	2	4	7	8	7	3	1	0.5
Offshore Emissions													
Gas Processing[10]	--	--	--	--	--	19	53	82	92	78	33	14	6
Tankers at OS&T[11]	--	--	--	--	--	5	15	23	26	22	9	4	1
Tankers In Transit[12]	--	--	--	--	--	55	159	242	274	233	101	43	17
Subtotal	--	0.2	0.2	--	2	81	232	354	400	340	146	62	25
TOTAL (Scenarios 1 and 2)	5	19	23	7	70	160	409	608	668	548	256	130	69

Table V-23 (continued)

	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1995	2000	2005
8. SCENARIO 1A:													
Onshore Emissions													
Pipeline Construction[7]	--	--	--	--	2	--	--	--	--	--	--	--	--
Gas Processing[10]	--	--	--	--	--	19	53	82	92	78	33	14	6
Miscellaneous[8]	Neg.	0.2	0.2	Neg.	0.2	0.3	0.5	0.5	0.4	0.2	0.2	0.2	0.2
Tankers In Port[9]	--	--	--	--	--	2	4	7	8	7	3	1	0.5
Offshore Emissions													
Additional Subsea Pipeline Installation[3]	--	--	--	--	2	--	--	--	--	--	--	--	--
Additional Support Activity[4]	--	--	--	--	1	--	--	--	--	--	--	--	--
Tankers at OS&T[11]	--	--	--	--	--	5.1	15	23	26	22	9.4	4.0	1.6
Tankers In Transit[12]	--	--	--	--	--	55	159	242	274	233	101	43	17
Subtotal	--	0.2	0.2	--	5	81	232	354	400	340	147	62	25
TOTAL (Scenario 1A)	5	19	23	7	73	160	409	608	668	540	257	130	69
C. SCENARIO 3:													
Onshore Emissions													
Pipeline Installation[7]	--	--	--	--	2	--	--	--	--	--	--	--	--
Miscellaneous[8]	Neg.	0.2	0.2	Neg.	0.2	0.3	0.5	0.5	0.4	0.2	0.2	0.2	0.2
Offshore Emissions													
Gas Processing[10]	--	--	--	--	--	19	53	82	92	78	33	14	6
Tankers at OS&T[13]	--	--	--	--	--	8	22	34	38	32	14	6	3
Tankers In Transit[14]	--	--	--	--	--	6	18	28	31	26	11	5	2
Subtotal	--	0.2	0.2	--	2	33	93	144	161	136	58	25	11
TOTAL (Scenario 3)	5	19	22	7	70	112	270	398	429	344	168	93	55

Table V-23 (continued)

1. Based on number of wells expected to be drilled as presented in Table V-2 and emissions per day per well drilled as presented in Table A-12 in Appendix A.

2. Based on number of platforms expected to be installed as presented in Table V-3 and emissions per day per platform installed as presented in Table A-13 in Appendix A.

3. Based on miles of pipeline expected to be installed as presented in Table V-4 and emissions per day for subsea pipeline installation as presented in Table A-14 in Appendix A.

4. Based on number of wells expected to be drilled as presented in Table V-2 and emissions per day per well drilled as presented in Table A-15 in Appendix A.

5. Based on emissions presented in Tables A-12, A-13, A-14, A-16, and A-17 in Appendix A.

6. Based on emission factors for diesel fired turbines presented in Table A-1 in Appendix A, power usage factors presented in Table A-3 in Appendix A and production level presented in Table V-1.

7. See Table A-40 in Appendix A for annual emissions associated with overland pipeline construction.

8. Includes workers' vehicles and helicopter. Based on emissions presented in Tables A-12, A-13, A-14, A-16 and A-17 in Appendix A.

9. Emissions would occur while the tanker or barge is docked at San Francisco. Based upon per visit emissions given in Table A-50 and expected number of voyages required as presented in Table A-47 in Appendix A.

10. Based on emission factors for gas processing presented in Table A-1 in Appendix A and production level presented in Table V-1.

11. Emissions would occur while the tanker or barge is docked at the OS&T. Based upon per visit emissions given in Table A-50 in Appendix A and expected number of voyages required as presented in Table A-37 in Appendix A.

12. Emissions would occur while the tanker or barge is en route between the OS&T and the dock in San Francisco. Based upon per visit emissions given in Table A-50 in Appendix A and the expected number of voyages required as presented in Table A-47 in Appendix A.

13. Emissions occur while the tanker or barge is docked at the OS&T. Based upon per visit emissions given in Table A-53 in Appendix A and the expected number of voyages required as presented in Table A-47 in Appendix A.

14. Emissions would occur while the tanker is traveling in waters adjacent ot Mendocino County. Based upon per visit emissions given in Table A-53 in Appendix A and the expected number of voyages required as presented in Table A-47 in Appendix A.

Table V-24. ANNUAL CARBON MONOXIDE EMISSIONS ASSOCIATED WITH LEASE SALE NO. 53 OCS OIL AND GAS DEVELOPMENT - POINT ARENA ZONE (MEAN RESOURCE ESTIMATE) (tons/year)

	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1995	2000	2005
OFFSHORE OPERATIONS COMMON TO ALL SCENARIOS													
Exploratory/Delineation Drilling[1]	2	7	8	3	--	--	--	--	--	--	--	--	--
Platform Installation[2]	--	--	--	--	102	--	--	--	--	--	--	--	--
Pipeline Installation(13 days)[3]	--	--	--	--	6	--	--	--	--	--	--	--	--
Development Drilling[4]	--	--	--	--	--	3	5	5	3	--	--	--	--
Supportive Activity[5]	8	35	41	13	50	72	103	136	128	81	81	81	81
Production Power Generation[6]	--	--	--	--	--	16	46	71	80	68	29	13	5
Oil Processing[7]	--	--	--	--	--	1	1	2	2	2	1	Neg.	Neg.
(Subtotal-Emissions from Common Offshore Operations)	10	42	49	16	158	92	155	214	213	151	111	94	89
A. SCENARIOS 1 AND 2:													
Onshore Emissions													
Pipeline Construction[8]	--	--	--	--	7	--	--	--	--	--	--	--	--
Miscellaneous[9]	2	7	9	3	19	21	33	40	35	18	18	18	18
Tankers In Port[10]	--	--	--	--	--	0.01	0.03	0.05	0.06	0.05	0.02	0.01	Neg.
Offshore Emissions													
Tankers at OS&T[11]	--	--	--	--	--	0.01	0.04	0.06	0.07	0.05	0.03	0.01	Neg.
Tankers In Transit[12]	--	--	--	--	--	0.01	0.03	0.05	0.06	0.04	0.02	0.01	Neg.
Subtotal	2	7	9	3	26	21	33	40	35	18	18	18	18
TOTAL (Scenarios 1 and 2)	12	49	58	19	184	113	188	254	248	169	129	112	107

Table V-24 (continued)

	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1995	2000	2005
B. SCENARIO 1A:													
Onshore Emissions													
Pipeline Construction[8]	--	--	--	--	7	--	--	--	--	--	--	--	--
Miscellaneous[9]	2	7	9	3	20	21	33	40	35	18	18	18	18
Tankers In Port[10]	--	--	--	--	--	0.01	0.03	0.05	0.06	0.05	0.02	0.01	Neg.
Offshore Emissions													
Pipeline Installation[3]	--	--	--	--	4	--	--	--	--	--	--	--	--
Additional Support Activity[4]	--	--	--	--	2	--	--	--	--	--	--	--	--
Tankers at OS&T[11]	--	--	--	--	--	0.01	0.04	0.06	0.07	0.05	0.03	0.01	Neg.
Tankers In Transit[12]	--	--	--	--	--	0.01	0.03	0.05	0.06	0.04	0.02	0.01	Neg.
Subtotal	2	7	9	3	33	21	33	40	35	18	18	18	18
TOTAL (Scenario 1A)	12	49	58	19	191	53	188	254	248	169	129	112	107
C. SCENARIO 3:													
Onshore Emissions													
Pipeline Installation[8]	--	--	--	--	7	--	--	--	--	--	--	--	--
Miscellaneous[9]	2	7	9	3	19	21	33	40	35	18	18	18	18
Offshore Emissions													
Tankers at OS&T[13]	--	--	--	--	--	0.01	0.04	0.06	0.07	0.05	0.03	0.01	Neg.
Tankers In Transit[14]	--	--	--	--	--	0.01	0.03	0.05	0.06	0.04	0.02	0.01	Neg.
Subtotal	2	7	9	3	26	21	33	40	35	18	18	18	18
TOTAL (Scenario 3)	12	49	58	19	184	113	188	254	248	169	129	112	107

Table V-24. (continued)

1. Based on number of wells expected to be drilled as presented in Table V-2 and emissions per day per well drilled as presented in Table A-12 in Appendix A.

2. Based on number of platforms expected to be installed as presented in Table V-3 and emissions per day per platform installed as presented in Table A-13 in Appendix A.

3. Based on the length of pipeline expected to be installed as presented in Table V-4 and emissions per day for subsea pipeline installation as presented in Table A-14 in Appendix A.

4. Based on number of wells expected to be drilled as presented in Table V-2 and emissions per day per well drilled as presented in Table A-15 in Appendix A.

5. Based on emissions presented in Tables A-12, A-13, A-14, A-16 and A-17 in Appendix A.

6. Based on emission factors for diesel fired turbines presented in Appendix A in Table A-1, power usage factors presented in Table A-3 in Appendix A and production level presented in Table V-1.

7. Based on emission factors for natural gas combustion presented in Table A-1 in Appendix A, an average heat requirement of 15,000 Btu/bbl (Energy Resources Co., 1977) and production level presented in Table V-1.

8. See Table A-40 in Appendix A for annual emissions associated with overland pipeline construction.

9. Includes workers' vehicles and helicopter. Based on emissions presented in Tables A-12, A-13, A-14, A-16 and A-17 in Appendix A.

10. Emissions would occur while the tanker or barge is docked at San Francisco. Based upon per visit emissions given in Table A-50 and expected number of voyages required as presented in Table A-47.

11. Emissions would occur while the tanker or barge is docked at the OS&T. Based upon per visit emissions given in Table A-50 and the expected number of voyages required as presented in Table A-47.

12. Emissions would occur while the tanker or barge is en route between the OS&T and the dock in San Francisco. Based upon per visit emissions given in Table A-50 and the expected number of voyages required as presented in Table A-47.

13. Emissions would occur while the tanker is docked at the OS&T. Based upon per visit emissions given in Table A-53 and the expected number of voyages required as presented in Table A-47.

14. Emissions would occur while the tanker is traveling in waters adjacent to Mendocino County. Based upon per visit emissions given in TableA-53 and the expected number of voysges required as presented in Table A-47.

Table V-25. ANNUAL TOTAL SUSPENDED PARTICULATE EMISSIONS ASSOCIATED WITH LEASE SALE NO. 53 OCS OIL AND GAS DEVELOPMENT POINT ARENA (MEAN RESOURCE ESTIMATE) (tons/year)

	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1995	2000	2005
OFFSHORE OPERATIONS COMMON TO ALL SCENARIOS													
Exploratory/Delineation Drilling[1]	Neg.	Neg.	Neg.	Neg.	--	--	--	--	--	--	--	--	--
Platform Installation[2]	--	--	--	--	31	--	--	--	--	--	--	--	--
Pipeline Installation (13 days)[3]	--	--	--	--	2	--	--	--	--	--	--	--	--
Development Drilling[4]	--	--	--	--	--	0.8	2	2	1	--	--	--	--
Supportive Activity[5]	2	10	12	4	15	21	30	39	37	23	23	23	23
Production Power Generation[6]	--	--	--	--	--	7	21	32	36	30	13	6	2
Oil Processing[7]	--	--	--	--	--	0.2	1	1	1	1	0.4	0.2	0.1
(Subtotal-Emissions from Common Offshore Operations)	2	10	12	4	48	29	54	74	75	54	36	29	25
A. SCENARIOS 1 AND 2:													
Onshore Emissions													
Pipeline Construction[8]	--	--	--	--	1	--	--	--	--	--	--	--	--
Miscellaneous[9]	Neg.	0.2	0.2	Neg.	1	0.7	1	1	1	0.4	0.4	0.4	0.4
Tankers In Port[10]	--	--	--	--	--	0.1	0.4	0.6	0.7	0.6	0.3	0.1	0.04
Offshore Emissions													
Tankers at OS&T[11]	--	--	--	--	--	0.3	0.9	1	1	1	0.6	0.2	0.1
Tankers In Transit[12]	--	--	--	--	--	3	9	14	16	14	6	3	1
Subtotal	--	0.2	0.2	--	2	4	12	17	19	16	7	3	2
TOTAL (Scenarios 1 and 2)	2	10.2	12.2	4	50	33	66	91	94	70	44	32	27

Table V-25. (continued)

	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1995	2000	2005
B. SCENARIO 1A:													
Onshore Emissions													
Pipeline Construction[8]	--	--	--	--	1	--	--	--	--	--	--	--	--
Miscellaneous[9]	Neg.	0.2	0.2	Neg.	1	0.2	1	1	1	0.4	0.4	0.4	0.4
Tankers In Port[10]	--	--	--	--	--	0.1	0.4	0.6	0.7	0.6	0.3	0.1	0.1
Offshore Emissions													
Pipeline Installation[3]	--	--	--	--	1	--	--	--	--	--	--	--	--
Additional Support Activity[4]	--	--	--	--	1	--	--	--	--	--	--	--	--
Tankers at OS&T[11]	--	--	--	--	--	0.3	0.9	1	1	1	0.6	0.2	0.2
Tankers In Transit[12]	--	--	--	--	--	3	9	14	16	14	6	3	1
Subtotal	--	0.2	0.2	--	4	4	12	17	19	16	7	3	2
TOTAL (Scenario 1A)	2	10	12	4	52	32	66	91	94	70	44	32	27
C. SCENARIO 3:													
Onshore Emissions													
Pipeline Installation[8]	--	--	--	--	1	--	--	--	--	--	--	--	--
Miscellaneous[9]	Neg.	0.2	0.2	Neg.	1	0.7	1	1	1	0.4	0.4	0.4	0.4
Offshore Emissions													
Tankers at OS&T[13]	--	--	--	--	--	0.05	1	2	2	2	0.8	0.4	0.2
Offshore Transit[14]	--	--	--	--	--	0.4	1	2	2	2	0.7	0.3	0.1
Subtotal	--	0.2	0.2	--	2	1	3	5	5	4	2	1	0.7
TOTAL (Scenario 3)	2	10	12	4	50	30	57	79	80	58	38	30	26

Table V-25. (continued)

1. Based on number of wells expected to be drilled as presented in Table V-2 and emissions per day per well drilled as presented in Table A-12 in Appendix A.

2. Based on number of platforms expected to be installed as presented in Table V-3, and emissions per day per platform installed as presented in Table A-13 in Appendix A.

3. Based on the length of pipeline expected to be installed as presented in Table V-4 and emissions per day for subsea pipeline installation as presented in Table A-14 in Appendix A.

4. Based on number of wells expected to be drilled as presented in TableV-2 and emissions per day per well drilled as presented in Table A-15 in Appendix A.

5. Based on emissions presented in Tables A-12, A-13, A-14, A-16 and A-17 in Appendix A.

6. Based on emission factors for diesel fired turbines presented in Appendix A in Table A-1 power usage factors presented in Table A-3 in Appendix A and production level presented in Table V-1.

7. Based on emission factors for natural gas combustion presented in TableA-1 in Appendix A, an average heat requirement of 15,000 Btu/bbl (Energy Resources Co., 1977) and production level presented in Table V-1.

8. See Table A-40 in Appendix A for annual emissions associated with overland pipeline construction.

9. Includes workers' vehicles and helicopter. Based on emissions presented in Tables A-12, A-13, A-14, A-16 and A-17 in Appendix A.

10. Emissions would occur while the tanker or barge is docked at San Francisco. Based upon per visit emissions given in Table A-50 in Appendix A and expected number of voyages required as presented in Table A-47 in Appendix A.

11. Emissions would occur while the tanker or barge is docked at the OS&T. Based upon per visit emissions given in Table A-50 in Appendix A and the expected number of voyages required as presented in Table A-47 in Appendix A.

12. Emissions would occur while the tanker or barge is en route between the OS&T and the dock in San Francisco. Based upon per visit emissions given in Table A-50 in Appendix A and the expected number voyages required as presented in Table A-47 in Appendix A.

13. Emissions would occur while the tanker is docked at the OS&T. Based upon per visit emissions given in Table A-53 in Appendix A and the expected number of voyages required as presented in Table A-47 in Appendix A.

14. Emissions would occur while the tanker is traveling in waters adjacent to Mendocino County. Based upon per visit emissions given in Table A-53 in Appendix A and the expected number of voyages required as presented in Table A-47 in Appendix A.

b) Transportation Emissions

As was stated in Section V.D.1, all gas would be transported to shore via pipeline. The resultant emissions have been incorporated into the estimate of emissions associated with production and processing.

Oil would be shipped by tanker to San Francisco in Transportation Scenarios 1, 1A or 2, or it would be shipped to the Gulf Coast, e.g., Galveston, Texas, in Transportation Scenario 3. The size of ships to be used and the frequency of their trips have been summarized in Tables A-42, A-47, A-48 and A-49 in Appendix A. Hydrocarbon losses during loading would be the most significant emission in any of the four proposed transportation scenarios. Significant quantities of sulfur oxides would be emitted by the ships in transit; however, because the ships are mobile sources, the sulfur oxides would be dispersed over a rather large area. Listed in the footnotes for Tables A-50 - A-53, in Appendix A, which describe ship emissions on a per visit basis, is a breakdown of the time a ship would spend passing along the coast of each county in California.

c) Onshore Emissions

Should Transportation Scenario 1A be adopted, the onshore gas processing plant, located about two miles inland, would be a significant emission source. The facility would emit hydrocarbons, hydrogen sulfide and sulfur oxides from its processing activities, and nitrogen oxides from diesel-fired turbines in its power plant.

San Francisco would serve as the land base for tankers in Transportation Scenarios 1, 1A and 2, and for supply boats in all scenarios. Hydrocarbons released by tankers ballasting in harbor would be a significant onshore emission, but the quantity would be relatively small compared to the total hydrocarbons emitted from the onshore gas processing facility

Included in the small quantity of miscellaneous onshore emissions are vehicular traffic by employees, delivery trucks and helicopters.

ii. Maximum Hourly Emissions

The maximum hourly emissions for the reactive pollutant combination of nitrogen oxides and hydrocarbons, as well as for the non-reactive pollutants, i.e., sulfur oxides, carbon monoxide and particulate matter, would occur in 1989. This would be the year of maximum production. Activities contributing to the maximum one hour emissions would be: 1) production at up to 61 wells; 2) drilling additional wells; 3) processing oil and gas; 4) loading a tanker 5) a supply and crew boat docked at the platform; and 6) a supply and crew boat waiting nearby. The specific assumptions are given in the footnotes to Table V-26.

iii. Maximum Daily Emissions

Maximum daily emissions have been calculated by carefully reckoning what activities could actually occur within a given 24 hours. Production, processing, drilling and evaporation could occur continuously at a fixed point for 24 hours. Tankers, support boats, and vehicular traffic could be involved in several activities at different locations over the same 24 hours.

The maximum daily emissions calculated are presented in Table V-26. The major emission sources on a daily basis would be power generation, tankering, and gas processing; they would occur in 1989, the year of maximum production. Statements in the preceding subsection about annual emissions are also applicable to a daily situation.

iv. Comparison with Regional Emissions

The 1976 emission inventory for Mendocino County is presented in Table V-27 The emissions occurring in Mendocino County are chosen for comparison with proposed Lease Sale No. 53 OCS activity in the Point Arena zone because it lies directly east of the OCS zone. Furthermore, the predominant wind direction indicates that emissions from this zone would be directed toward this county. Though the peak emission year from Lease Sale No. 53 OCS activity in the Point Arena zone is expected to be 1989, the only emission inventory available for Mendocino County is for 1976.

As may be seen in Table V-27, the countywide emissions are relatively low when compared to a more populated area such as Humboldt County (see Table V-19). There is little industry in Mendocino County. Most of the emissions occur from mobile sources, primarily automobiles. Waste burning also accounts for a significant portion of the total emissions.

Presented in Table V-28 is a comparison of the estimated peak annual emissions which would be generated by proposed Lease Sale No. 53 OCS activity in the Point Arena zone and the 1976 Mendocino County emission inventory. Caution should be used in interpreting the results of this comparison. A substantial quantity of the total annual estimated emissions associated with OCS activity in the lease tract would occur from support vessels traveling between the Point Arena zone and the San Francisco Bay Area. These emissions would be distributed along a path approximately 170 miles in length.

It should also be noted that because of the simplifying assumptions made and described in Section V.D.1., some degree of uncertainty exists in the actual estimates of emissions from Lease Sale No. 53 activity. Also, since comparisons of emissions were made using the estimated peak emission from OCS activity in the Point Arena Zone, emissions, and thus comparative percentages, may be substantially lower in other years of Lease Sale No. 53 OCS activity.

As shown in Table V-28, it is expected that comparatively significant quantities of sulfur oxides (SO_x), nitrogen oxides (NO_x) and hydrocarbons (HC) would be emitted during Lease Sale No. 53 OCS activity in the Point Arena zone. Emissions of carbon monoxide (CO) and total suspended particulates (TSP) are not expected to be significant in comparison with the total county emissions.

c. Bodega

i. Total Annual Emissions

a) Offshore Emissions

Annual emissions from OCS activity in the Bodega zone are presented in Tables V-29 to V-33 by pollutant, activity, year, and transportation scenario for the mean resource estimate.

Table V-26. MAXIMUM DAILY AND HOURLY EMISSIONS ASSOCIATED WITH LEASE SALE NO. 53 OCS OIL AND GAS DEVELOPMENT - POINT ARENA ZONE (MEAN RESOURCE ESTIMATE; PEAK PRODUCTION YEAR - 1989)

Source	Emissions lbs/day (lbs/hr)					
	HC	NO_x	SO_x	CO	TSP	H_2S
OFFSHORE SOURCES COMMON TO ALL SCENARIOS						
Development Drilling[1]	24 (1)	296 (12)	156 (6)	64(3)	20 (0.8)	--
Support Activity[2]	188 (9)	8,261 (400)	564 (27)	1,241 (60)	361 (18)	--
Power Generation[3]	196 (8)	1,595 (66)	1,119 (47)	439 (18)	196 (8)	--
Evaporative Losses[4]	2,245 (94)	--	--	--		--
ONSHORE SOURCES COMMON TO ALL SCENARIOS						
Miscellaneous[5]	28 (1)	46 (2)	6 (0.3)	432 (18)	12 (0.5)	--
Subtotal	2,681 (113)	10,198 (481)	1,845 (80)	2,176 (99)	589 (28)	--
SCENARIOS 1,2						
Offshore Sources						
Gas Processing[6]	9,954 (415)	47.6(20)	502 (21)	--	--	123 (5)
Oil Processing[7]	5 (0.2)	65 (3)	--	13 (0.5)	7 (0.3)	--
Tankers at OS&T[8]	7,222 (815)	58 (2)	540 (27)	1 (0.1)	32 (2)	--
Tankers near Platform[9]	135	45	330	0.6	20	--
Tankers in Sea Passage[10]	242	200	1,281	2	79	--
Subtotal	17,558 (1,230)	844 (24)	2,651 (48)	17 (0.6)	138(2)	123 (5)
TOTAL (Scenario 1,2)	20,239 (1,343)	11,042 (505)	4,498 (128)	2,193 (100)	727 (30)	123 (5)

Table V-26 (continued)

Source	Emissions lbs/day (lbs/hr) HC	NO_x	SO_x	CO	TSP	H_2S
SCENARIO 1A						
Onshore Sources						
Gas Processing[7]	9,954 (415)	476 (20)	502 (21)	--	--	123 (5)
Offshore Sources						
Oil Processing[6]	5 (0.2)	65 (3)	--	13 (0.5)	7 (0.3)	--
Tankers at OS&T[8]	7,222 (815)	58 (2)	540 (27)	1 (0.1)	32 (2)	--
Tankers near Platform[9]	135	45	440	0.5	20	--
Tankers in Sea Passage[10]	242	200	1,281	2.4	79	--
Subtotal	17,558 (1,230)	844 (24)	2,653 (48)	17 (0.6)	138 (2)	123 (5)
TOTAL (Scenario 1A)	20,239 (1,343)	11,042 (505)	4,498 (128)	2,193 (100)	727 (30)	123 (5)
SCENARIO 3						
Offshore Sources						
Oil Processing[6]	5 (0.2)	65 (3)	--	13 (0.5)	7 (0.3)	--
Gas Processing[7]	9,954 (415)	476 (20)	502 (27)	--	--	123 (5)
Tankers at OS&T[11]	13,602 (800)	230 (10)	1,508 (65)	3 (0.1)	90 (4)	--
Subtotal	23,561 (1,215)	771 (33)	2,010 (86)	16 (0.6)	97 (4)	123 (5)
TOTAL (Scenario 3)	26,242 (1,328)	10,969 (514)	3,855 (166)	2,192 (100)	686 (32)	123 (5)

Table V-26 (continued)

1. Based on 4 wells being drilled simultaneously and emissions per day per well drilled presented in Table A-15 in Appendix A.

2. Daily emissions based on Tables A-16 and A-17 presented in Appendix A. Hourly emissions assume 2 crew boats and 6 supply boats operating simultaneously and emission factors presented in Table A-1 of Appendix A.

3. Based on emission factors for diesel fired turbines presented in Table A-1 of Appendix A and production level presented in Table V-1 .

4. Based on evaporative emission factors presented in Appendix A in Table A-1 and production level presented in Table V-1.

5. Includes workers' vehicles and helicopter. Based on emissions presented in Tables A-16 and A-17 in Appendix A.

6. Based on emission factors for natural gas combustion presented in Table A-1 in Appendix A, an average heat requirement of 15,000 BTU/bbl and production level presented in Table V-1.

7. Based on emission factors for gas processing presented in Table A-1 of Appendix A and production level presented in Table V-1.

8. Based on 8.75 hours of loading, 5 hours of discharging ballast and 2 hours of boteling. Loading would produce the maximum hourly emissions.

9. Based on 3 hours of maneuvering about the platform.

10. Based on 5.25 hours of sea passage.

11. Based on 5 hours of discharging ballast, 2 hours of boteling, and 17 hours of loading. Because the entire selected 24 hours period is accounted for, no emissions for maneuvering or in transit times are given. Loading would produce maximum hourly emissions.

Table V-27. 1976 EMISSIONS FOR MENDOCINO COUNTY[1]

Source	Emissions - tons/year (% of total emissions)				
	HC[2]	NO_x	SO_x	CO	TSP
Petroleum[3]	913(16%)	--	--	--	--
Organic Solvents	584(10%)	--	--	--	--
Combustion of Fuels	328(6%)	548(18%)	110(43%)	2,008(9%)	1,898(49%)
Waste Burning	1,423(24%)	219(7%)	--	8,103(34%)	1,132(29%)
Other Stationary[4]	402(7%)	37(1%)	--	1,241(5%)	584(15%)
Mobile[5]	2,190(37%)	2,336(74%)	146(57%)	12,410(52%)	255(7%)
Total	5,840(100%)	3,140(100%)	256(100%)	23,762(100%)	3,869(100%)

1. Source: California North Coast Air Basin Air Pollution Control District, Air Pollution Control Plan for the California North Coast Air Basin (1977). Emissions are for 1976. No other data are available.
2. Refers to total hydrocarbons emissions.
3. Emissions are from petroleum marketing only.
4. Includes industrial emissions and miscellaneous area source emissions.
5. Includes all on-road vehicles, aircraft, ships and railroads.

Table V-28. COMPARISON OF EMISSIONS ASSOCIATED WITH LEASE SALE NO. 53 ACTIVITIES IN THE POINT ARENA ZONE WITH REGIONAL EMISSION INVENTORY FOR MENDOCINO COUNTY

Pollutant	Peak Emission Year	Tons Per Year[1] (Percentage of Emissions Associated with Lease Sale No. 53 Activities to Regional Emission Inventory)[2,3] Transportation Scenario 1	Transportation Scenario 1-A	Transportation Scenario 2	Transportation Scenario 3
Total Hydrocarbons	1989	2,721(46%)	2,721(46%)	2,721(46%)	2,622(45%)
Nitrogen Oxides	1988	1,322(42%)	1,322(42%)	1,322(42%)	1,281(42%)
Sulfur Oxides	1989	668(270%)	668(270%)	668(270%)	429(168%)
Carbon Monoxide	1988	254(1%)	254(1%)	254(1%)	254(1%)
Total Suspended Particulate	1989	94(2%)	94(2%)	94(2%)	94(2%)

1. Based on the USGS mean resource estimate.
2. Emissions associated with Lease Sale No. 53 OCS activity in the Point Arena Zone have been compared to 1976 onshore emissions for Mendocino County. Emissions for the Mendocino County have been obtained from the Air Pollution Control Plan for the California North Coast Air Basin (California North Coast Air Basin Air Pollution Control Council, 1977).
3. Portions of estimated emissions associated with Lease Sale No. 53 OCS activity in the Point Arena Zone occur from mobile sources outside of zone.

As shown in Tables V-29 to V-33 for the mean resource estimate, exploratory and delineation drilling would occur during the first three years of OCS activity in the zone. The emissions which would occur during the exploration phase are expected to be small in comparison to pollutants emitted during other phases of Lease Sale No. 53 activity.

Based on the USGS mean resource estimate, no activity is expected to occur within the zone in 1984. Development would begin in 1985 with the installation of one production platform and one offshore storage and loading facility. These activities are expected to result in high emissions of nitrogen oxides, carbon monoxide, sulfur oxide and total suspended particulates. The peak emission year for all pollutants except sulfur oxides and hydrocarbons is expected to be in 1985.

Production would begin in 1986, with oil being produced and gas being reinjected. Production would reach its peak in 1987, in the mean resource estimate. Emissions from fugitive sources would be the main cause of the high hydrocarbon emission level estimated for 1987.

Supportive activity would produce a large portion of the nitrogen oxides, sulfur oxides, carbon monoxide and total suspended particulate emissions every year. The primary reason is the distance that all supply boats would travel from their point of origin in the San Francisco Bay Area -- a 90 mile round trip. It should be noted that while emissions from support vessels may be high, the pollutants would be emitted along the entire path the vessel travels.

b) Transportation Emissions

Oil produced in the Bodega zone would either be barged to refineries in the San Francisco Bay area (as in Transportation Scenarios 1, 1A, 2) or tankered to Galveston, Texas (as in Transportation Scenario 3). The sizes of the barges and tankers used for each resource estimate are summarized in Appendix A in Table A-42.

Hydrocarbon losses from tanker and barge loading would be the most significant emissions from the transport of oil in any of the four transportation scenarios. Sulfur oxides from tankers in transit (Transportation Scenario 3) and nitrogen oxides generated by tugboats towing barges (Transportation Scenarios 1, 1A, and 2) would also be major emissions. Pollutants associated with transportation, however, would be emitted over the total area each vessel travels. Annual transit emissions between the San Francisco Bay Area and the Bodega zone are presented in Tables V-29 - V-31 for the mean resource estimate (Transportation Scenarios 1, 1A, and 2). Annual tanker transit emissions between the zone and the Southern Mendocino County border are also presented in Tables V-29 - V-33 or the mean resource estimate (Transportation Scenario 3).

c) Onshore Emissions

No new onshore facilities are predicted for this zone (BLM, 1979b). The only emissions would be from workers' vehicles and other miscellaneous support vehicles and the activities associated with unloading barges in the San Francisco Bay (Transportation Scenarios 1, 1A, 2). Onshore emissions associated with tanker operations in Galveston, Texas (Transportation Scenario 3) were not considered.

Table V-29. ANNUAL HYDROCARBON EMISSIONS ASSOCIATED WITH LEASE SALE NO. 53 OCS OIL AND GAS DEVELOPMENT - BODEGA ZONE (MEAN RESOURCE ESTIMATE)

(tons/year)

	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1995	2000	2005
OFFSHORE OPERATIONS COMMON TO ALL SCENARIOS													
Exploratory/Delineation Drilling[1]	0.5	0.7	0.2	--	--	--	--	--	--	--	--	--	--
Platform Installation[2]	--	--	--	--	23	--	--	--	--	--	--	--	--
Development Drilling[3]	--	--	--	--	--	0.5	0.7	--	--	--	--	--	--
Supportive Activity[4]	0.5	0.8	0.3	--	2	3	3	2	2	2	2	2	2
Production Power Generation[5]	--	--	--	--	--	2	6	5	5	4	2	1	0.6
Oil Processing[6]	--	--	--	--	--	--	0.2	0.2	0.1	Neg.	Neg.	Neg.	Neg.
Evaporative Losses[7]	--	--	--	--	--	25	61	53	47	41	22	11	6
(Subtotal-Emissions from Common Offshore Operations)	1.0	1.5	0.5	--	25	30	71	60	54	47	26	14	9
A. SCENARIOS 1, 1A AND 2:													
Onshore Emissions													
Miscellaneous[8]	0.2	0.3	0.1	--	1	1	1	0.7	0.7	0.7	0.7	0.7	0.7
Tankers in Port[9]	--	--	--	--	--	0.6	2	1	1	1	0.6	0.3	0.2
Offshore Emissions													
Tankers at OSA[10]	--	--	--	--	--	44	116	100	88	80	40	22	11
Tankers in Transit[11]	--	--	--	--	--	2	4	3	3	3	1	0.8	0.4
Subtotal	0.2	0.3	0.1	--	1	48	123	105	93	85	42	24	12
TOTAL (Scenarios 1, 1A AND 2)	1	2	0.6	--	26	78	194	165	147	132	68	38	21
B. SCENARIO 3:													
Onshore Emissions													
Miscellaneous[8]	0.2	0.3	0.1	--	1	1	1	0.7	0.7	0.7	0.7	0.7	0.7
Offshore Emissions													
Tankers at OSA[12]	--	--	--	--	--	25	61	50	46	43	21	14	7
Tankers in Transit[13]	--	--	--	--	--	0.1	0.1	0.1	0.1	0.1	Neg.	Neg.	Neg.
Subtotal	0.2	0.3	0.1	--	1	26	62	57	47	44	22	15	8
TOTAL (Scenario 3)	1	2	0.6	--	26	57	133	111	101	91	48	29	16

Table V-29 (continued)

1. Based on number of wells expected to be drilled as presented in Table V-2 and emissions per day per well drilled as presented in Table A-19 in Appendix A.

2. Based on number of platforms expected to be installed as presented in Table V-3 and emissions per day per platform installed as presented in Table A-20 in Appendix A.

3. Based on number of wells expected to be drilled as presented in Table V-5 and emissions per day per well drilled as presented in Table A-22 in Appendix A.

4. Based on emissions presented in Tables A-19, A-20, A-23, and A-24 in Appendix A.

5. Based on emission factors for diesel fired turbines presented in Appendix A in Table A-1, power usage factors presented in Table A-3 in Appendix A and production level presented in Table V-1.

6. Based on emission factors for natural gas combustion presented in Table A-1 in Appendix A, an average heat requirement of 15,000 Btu/bbl (Energy Resources Co., 1977) and production level presented in Table V-1.

7. Based on evaporative emission factors presented in Table A-1 in Appendix A and production level presented in Table V-1.

8. Includes workers' vehicles and helicopter. Based on emissions presented in Tables A-19, A-20, A-23, and A-24 in Appendix A.

9. Emissions would occur while the tanker or barge is docked at San Francisco. Based upon per visit emissions given in Table A-54 in Appendix A and and expected number of voyages required as presented in Table A-47 in Appendix A.

10. Emissions would occur while the tanker or barge is docked at the OS&T. Based upon per visit emissions given in Table A-54 in Appendix A and the expected number of voyages required as presented in Table A-47 in Appendix A.

11. Emissions would occur while the tanker or barge is en route between the OS&T and the dock in San Francisco. Based upon per visit emissions given in Table A-54 in Appendix A and the expected number of voyages required as presented in Table A-47 in Appendix A.

12. Emissions would occur while the tanker is docked at the OS&T. Based upon per visit emissions given in Table A-57 in Appendix A and the expected number of voyages required as presented in Table A-47 in Appendix A.

13. Emissions would occur while the tanker is traveling in waters adjacent to Bay Area Air Quality Management District. Based upon per visit emissions given in Table A-57 in Appendix A and the expected number of voyages required as presented in Table A-47 in Appendix A.

Table V-30 ANNUAL NITROGEN OXIDES EMISSIONS ASSOCIATED WITH LEASE SALE NO. 53 OCS OIL AND GAS DEVELOPMENT - BODEGA ZONE
(MEAN RESOURCE ESTIMATE)
(tons/year)

	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1995	2000	2005
OFFSHORE OPERATIONS COMMON TO ALL SCENARIOS													
Exploratory/Delineation Drilling[1]	14	21	7	--	--	--	--	--	--	--	--	--	--
Platform Installation[2]	--	--	--	--	631	--	--	--	--	--	--	--	--
Development Drilling[3]	--	--	--	--	--	5	8	--	--	--	--	--	--
Supportive Activity[4]	22	33	11	--	98	114	148	81	81	81	81	81	81
Production Power Generation[5]						25	63	55	48	43	23	12	7
Oil Processing[6]	--	--	--	--	--	1	2	2	2	1	1	0.4	0.2
(Subtotal-Emissions from Common Offshore Operations)	36	54	18	--	729	145	221	138	131	125	105	93	88
A. SCENARIOS 1, 1A AND 2:													
Onshore Emissions													
Miscellaneous[7]	0.2	0.3	0.1	--	1	2	2	1	1	1	1	1	1
Tankers In Port[8]	--	--	--	--	--	6	13	11	10	9	5	3	1
Offshore Emissions													
Tankers at OS&T[9]	--	--	--	--	--	2	5	4	4	3	2	1	0.5
Tankers In Transit[10]	--	--	--	--	--	6	15	13	12	11	6	3	2
Subtotal	0.2	0.3	0.1	--	1	16	35	29	27	24	14	8	4
TOTAL (Scenarios 1, 1A and 2)	36	54	18	--	730	161	256	167	158	149	119	101	93
B. SCENARIO 3:													
Onshore Emissions													
Miscellaneous[7]	0.2	0.3	0.1	--	1	2	2	1	1	1	1	1	1
Offshore Emissions													
Tankers at OS&T[11]	--	--	--	--	--	0.4	1	0.8	0.7	0.7	0.3	0.2	0.2
Tankers In Transit[12]	--	--	--	--	--	0.8	2	2	1	1	1	0.4	0.1
Subtotal	0.2	0.3	0.1	--	1	3	5	4	3	3	2	2	1
TOTAL (Scenario 3)	36	54	18	--	730	148	226	142	134	128	107	96	89

Table V-30 (continued)

1. Based on number of wells expected to be drilled as presented in Table V-2 and emissions per day per well drilled as presented in Table A-19 in Appendix A.

2. Based on number of platforms expected to be installed as presented in Table V-3, and emissions per day per platform installed as presented in Table A-20 in Appendix A.

3. Based on number of wells expected to be drilled as presented in Table V-2 and emissions per day per well drilled as presented in Table A-22 in Appendix A.

4. Based on emissions presented in Tables A-19, A-20, A-23, and A-24 in Appendix A.

5. Based on emission factors for diesel fired turbines presented in Appendix A in Table A-1, power usage factors presented in Table A-3 in Appendix A and production level presented in Table V-1.

6. Based on emission factors for natural gas combustion presented in Table A-1 in Appendix A, an average heat requirement of 15,000 Btu/bbl (Energy Resources Co., 1977) and production level presented in Table V-1.

7. Includes workers' vehicles and helicopter. Based on emissions presented in Tables A-19, A-20, A-23, and A-24 in Appendix A.

8. Emissions would occur while the tanker or barge is docked at San Francisco. Based upon per visit emissions given in Table A-54 in Appendix A and and the expected number of voyages required as presented in Table A-47 in Appendix A.

9. Emissions would occur while the tanker or barge is docked at the OS&T. Based upon per visit emissions given in Table A-54 in Appendix A and the expected number of voyages required as presented in Table A-47 in Appendix A.

10. Emissions would occur while the tanker or barge is en route between the OS&T and the dock in San Francisco. Based upon per visit emissions given in Table A-54 in Appendix A and the expected number of voyages required as presented in Table A-47 in Appendix A.

11. Emissions would occur while the tanker is docked at the OS&T. Based upon per visit emissions given in Table A-57 in Appendix A and the expected number of voyages required as presented in Table A-47 in Appendix A.

12. Emissions would occur while the tanker is traveling in water adjacent to the Bay Area Air Quality Management District. Based upon per visit emissions given in Table A-57 in Appendix A and the expected number of voyages required as presented in Table A-47 in Appendix A.

Table V-31. ANNUAL SULFUR OXIDES EMISSIONS ASSOCIATED WITH LEASE SALE NO. 53 OCS OIL AND GAS DEVELOPMENT - BODEGA ZONE (MEAN RESOURCE ESTIMATE) (tons/year)

	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1995	2000	2005
OFFSHORE OPERATIONS COMMON TO ALL SCENARIOS													
Exploratory/Delineation Drilling[1]	1	1	0.5	--	--	--	--	--	--	--	--	--	--
Platform Installation[2]	--	--	--	--	42	--	--	--	--	--	--	--	--
Development Drilling[3]	--	--	--	--	--	3	4	--	--	--	--	--	--
Supportive Activity[4]	5	7	2	--	7	8	10	6	6	6	6	6	6
Production Power Generation[5]	--	--	--	--	--	14	34	29	26	23	13	6	4
(Subtotal-Emissions from Common Offshore Operations)	6	8	2	--	49	25	48	35	32	29	19	12	10
A. SCENARIOS 1,1A AND 2:													
Onshore Emissions													
Miscellaneous[6]	Neg.	Neg.	Neg.	--	0.2	0.3	0.3	0.2	0.2	0.2	0.2	0.2	0.2
Tankers In Port[7]	--	--	--	--	--	0.4	0.9	0.8	0.7	0.6	0.4	0.2	0.1
Offshore Emissions													
Tankers at OS&T[8]	--	--	--	--	--	0.1	0.3	0.3	0.2	0.2	0.1	0.07	0.03
Tankers In Transit[9]	--	--	--	--	--	0.4	1	0.9	0.8	0.7	0.4	0.2	0.1
Subtotal	Neg.	Neg.	Neg.	--	0.2	1	2	2	2	2	1	0.7	0.4
TOTAL (Scenarios 1, 1A and 2)	6	8	2	--	49	26	50	37	34	31	20	13	10
B. SCENARIO 3:													
Onshore Emissions													
Miscellaneous[6]	Neg.	Neg.	Neg.	--	0.2	0.3	0.3	0.2	0.2	0.2	0.2	0.2	0.2
Offshore Emissions													
Tankers at OS&T[10]	--	--	--	--	--	3	6	5	5	5	2	2	0.8
Tankers In Transit[11]	--	--	--	--	--	5	12	10	9	9	4	3	1
Subtotal	Neg.	Neg.	Neg.	--	0.2	8	18	15	14	14	6	5	2
TOTAL (Scenario 3)	6	8	2	--	49	33	66	50	46	42	25	17	12

Table V-31 (continued)

1. Based on number of wells expected to be drilled as presented in Table V-2 and emissions per day per well drilled as presented in Table A-19 in Appendix A.

2. Based on number of platforms expected to be installed aa presented in Table V-3, and emissions per day per platform installed as presented in Table A-20 in Appendix A.

3. Based on number of wells expected to be drilled as presented in Table V-2 and emissions per day per well drilled as presented in Table A-22 in Appendix A.

4. Based on emissions presented in Tables A-19, A-20, A-23 and A-24 in Appendix A.

5. Based on emission factors for diesel fired turbines presented in Appendix A in Table A-1, power usage factors presented in Table A-3 in Appendix A and production level presented in Table V-1.

6. Includes workers' vehicles and helicopter. Based on emissions presented in Tables A-19, A-20, A-23 and A-24 in Appendix A.

7. Emissions would occur while the tanker or barge is docked at San Francisco. Based upon per visit emissions given in Table A-54 in Appendix A and the expected number of voyages required as presented in Table A-47 in Appendix A.

8. Emissions would occur while the tanker or barge is docked at the OS&T. Based upon per visit emissions given in Table A-54 in Appendix A and the expected number of voyages required as presented in Table A-47 in Appendix A.

9. Emissions would occur while the tanker or barge is en route between the OS&T and the dock in San Francisco. Based upon per visit emissions given in Table A-54 in Appendix A and the expected number of voyages required as presented in Appendix A.

10. Emissions would occur while the tanker is docked at the OS&T. Based upon per visit emissions given in Table A-57 in Appendix A and the expected number of voyages required as presented in Table A-47 in Appendix A.

11. Emissions would occur while the tanker is traveling in waters adjacent to the Bay Area Air Quality Management District. Based upon per visit emissions given in Table A-57 in Appendix A and the expected number of voyages required as presented in Table A-47 in Appendix A.

Table V-32 ANNUAL CARBON MONOXIDE EMISSIONS ASSOCIATED WITH LEASE SALE NO. 53 OCS OIL AND GAS DEVELOPMENT - BODEGA ZONE (MEAN RESOURCE ESTIMATE) (tons/year)

	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1995	2000	2005
OFFSHORE OPERATIONS COMMON TO ALL SCENARIOS													
Exploratory/Delineation Drilling[1]	2	3	1	--	--	--	--	--	--	--	--	--	--
Platform Installation[2]	--	--	--	--	102	--	--	--	--	--	--	--	--
Development Drilling[3]	--	--	--	--	--	1	2	--	--	--	--	--	--
Supportive Activity[4]	3	5	2	--	15	17	22	12	12	12	12	12	12
Production Power Generation[5]	--	--	--	--	--	5	13	10	10	9	5	2	1
Oil Processing[6]	--	--	--	--	--	0.2	0.4	0.4	0.3	0.3	0.2	0.1	Neg.
(Subtotal-Emissions from Common Offshore Operations)	5	8	3	--	117	23	37	22	22	21	17	14	13
A. SCENARIOS 1,1A AND 2:													
Onshore Emissions													
Miscellaneous[7]	2	3	1	--	18	18	23	12	12	12	12	12	12
Tankers In Port[8]	--	--	--	--	--	0.9	2	2	2	1	0.8	0.4	0.2
Offshore Emissions													
Tankers at OS&T[9]	--	--	--	--	--	0.3	0.8	0.6	0.6	0.5	0.3	0.2	0.1
Tankers In Transit[10]	--	--	--	--	--	1	2	2	2	2	0.9	0.5	0
Subtotal	2	3	1	--	18	20	28	17	17	15	14	13	12
TOTAL (Scenarios 1, 1A and 2)	7	11	4	--	135	43	65	39	39	37	31	27	25
B. SCENARIO 3:													
Onshore Emissions													
Miscellaneous[7]	2	3	1	--	18	18	23	12	12	12	12	12	12
Offshore Emissions													
Tankers at OS&T[11]	--	--	--	--	--	Neg.	Neg.	Neg.	Neg.	Neg.	Neg.	Neg.	Neg.
Tankers In Transit[12]	--	--	--	--	--	Neg.	Neg.	Neg.	Neg.	Neg.	Neg.	Neg.	Neg.
Subtotal	2	3	1	--	18	18	23	12	12	12	12	12	12
TOTAL (Scenario 3)	7	11	4	--	135	41	60	36	34	33	29	26	25

Table V-32 (continued)

1. Based on number of wells expected to be drilled as presented in Table V-2 and emissions per day per well drilled as presented in Table A-19 in Appendix A.

2. Based on number of platforms expected to be installed as presented in Table V-3 and emissions per day per platform installed as presented in Table A-20 in Appendix A.

3. Based on number of wells expected to be drilled as presented in Table V-2 and emissions per day per well drilled as presented in Table A-22 in Appendix A.

4. Based on emissions presented in Tables A-19, A-20, A-23, and A-24 in Appendix A.

5. Based on emission factors for diesel fired turbines presented in Appendix A in Table A-1, power usage factors presented in Table A-3 in Appendix A and production level presented in Table

6. Based on emission factors for natural gas combustion presented in Table A-1 in Appendix A, an average heat requirement of 15,000 Btu/bbl (Energy Resources Co., 1977) and production level presented in Table V-1.

7. Includes workers' vehicles and helicopter. Based on emissions presented in Tables A-19, A-20, A-23, and A-24 in Appendix A.

8. Emissions would occur while the tanker or barge is docked at San Francisco. Based upon per visit emissions given in Table A-54 in Appendix A and the expected number of voyages required as presented in Table A-47 in Appendix A.

9. Emissions would occur while the tanker or barge is docked at the OS&T. Based upon per visit emissions given in Table A-54 in Appendix A and the expected number of voyages required as presented in Table A-47 in Appendix A.

10. Emissions would occur while the tanker or barge is en route between the OS&T and the dock in San Francisco. Based upon per visit emissions given in Table A-54 in Appendix A and the expected number of voyages required as presented in Table A-47 in Appendix A.

11. Emissions would occur while the tanker is docked at the OS&T. Based upon per visit emissions given in Table A-57 in Appendix A and the expected number of voyages required as presented in Table A-47 in Appendix A.

12. Emissions would occur while the tanker is traveling in waters adjacent to the Bay Area Air Quality Management District. Based upon per visit emissions given in Table A-57 in Appendix A and the expected number of voyages required as presented in Table A-47 in Appendix A.

Table V-33 ANNUAL TOTAL SUSPENDED PARTICULATE EMISSIONS ASSOCIATED WITH LEASE SALE NO. 53 OCS OIL AND GAS DEVELOPMENT-BODEGA ZONE (MEAN RESOURCE ESTIMATE) (tons/year)

	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1995	2000	2005
OFFSHORE OPERATIONS COMMON TO ALL SCENARIOS													
Exploratory/Delineation Drilling[1]	Neg.	Neg.	Neg.	--	--	--	--	--	--	--	--	--	--
Platform Installation[2]	--	--	--	--	31	--	--	--	--	--	--	--	--
Development Drilling[3]	--	--	--	--	--	0.4	0.6	--	--	--	--	--	--
Supportive Activity[4]	1	1	0.5	--	4	5	7	4	4	4	4	4	4
Production Power Generation[5]	--	--	--	--	--	2	6	5	5	4	2	1	0.6
Oil Processing[6]	--	--	--	--	--	0.1	0.2	0.2	0.2	0.1	0.1	Neg.	Neg.
(Subtotal-Emissions from Common Offshore Operations)	1	1	0.5	--	35	8	14	9	9	8	6	5	5
A. SCENARIOS 1,1A AND 2:													
Onshore Emissions													
Miscellaneous[7]	0.1	0.1	Neg.	--	0.6	0.7	0.8	0.6	0.6	0.6	0.6	0.6	0.6
Tankers In Port[8]	--	--	--	--	--	0.2	0.6	0.5	0.4	0.4	0.2	0.1	0.1
Offshore Emissions													
Tankers at OS&T[9]	--	--	--	--	--	0.1	0.2	0.2	0.2	0.2	0.1	0.04	0.02
Tankers In Transit[10]	--	--	--	--	--	0.3	0.7	0.6	0.5	0.5	0.3	0.1	0.1
Subtotal	0.1	0.1	Neg.	--	0.6	1	2	2	2	2	1	0.8	0.8
TOTAL (Scenarios 1, 1A and 2)	1	1	0.5	--	36	9	16	11	11	10	7	6	5
B. SCENARIO 3:													
Onshore Emissions													
Miscellaneous[7]	0.1	0.1	Neg.	--	0.6	0.7	0.8	0.6	0.6	0.6	0.6	0.6	0.6
Offshore Emissions													
Tankers at OS&T[11]	--	--	--	--	--	0.02	0.4	0.3	0.3	0.3	0.1	0.1	Neg
Tankers In Transit[12]	--	--	--	--	--	0.3	0.7	0.6	0.6	0.5	0.3	0.2	0.1
Subtotal	0.1	0.1	Neg.	--	0.6	1	2	2	2	1	1	0.9	0.7
TOTAL (Scenario 3)	1	1	0.5	--	36	9	16	11	11	9	7	6	5

Table V-33 (continued)

1. Based on number of wells expected to be drilled as presented in Table V-2 and emissions per day per well drilled as presented in Table A-19 in Appendix A.

2. Based on number of platforms expected to be installed as presented in Table V-3 and emissions per day per platform installed as presented in Table A-20 in Appendix A.

3. Based on number of wells expected to be drilled as presented in Table V-2 and emissions per day per well drilled as presented in Table A-22 in Appendix A.

4. Based on emissions presented in Tables A-19, A-20, A-22, and A-23 in Appendix A.

5. Based on emission factors for diesel fired turbines presented in Appendix A in Table A-1, power usage factors presented in Table A-3 in Appendix A and production level presented in Table

6. Based on emission factors for natural gas combustion presented in Table A-1 in Appendix A, an average heat requirement of 15,000 Btu/bbl (Energy Resources Co., 1977) and production level presented in Table V-1.

7. Includes workers' vehicles and helicopter. Based on emissions presented in Tables A-19, A-20, A-23 and A-24 in Appendix A.

8. Emissions would occur while the tanker or barge is docked at San Francisco. Based upon per visit emissions given in Table A-54 in Appendix A and the expected number of voyages required as presented in Table A-47 in Appendix A.

9. Emissions would occur while the tanker or barge is docked at the OS&T. Based upon per visit emissions given in Table A-54 in Appendix A and the expected number of voyages required as presented in Table A-47 in Appendix A.

10. Emissions would occur while the tanker or barge is en route between the OS&T and the dock in San Francisco. Based upon per visit emissions given in Table A-54 in Appendix A and the expected number of voyages required as presented in A-47.

11. Emissions would occur while the tanker is docked at the OS&T. Based upon per visit emissions given in Table A-57 in Appendix A and the expected number of voyages required as presented in Table A-47 in Appendix A.

12. Emissions would occur while the tanker is traveling in waters adjacent to the Bay Area Air Quality Management District. Based upon per visit emissions given in Table A-57 in Appendix A and the expected number of voyages required as presented in Table A-47 in Appendix A.

ii. Maximum Hourly Emissions

Maximum hourly emissions associated with the peak production year (1987) and the mean resource estimates are presented in Table V-34. Emissions are given by transportation scenario and activity generating each pollutant. Table V-35 presents nitrogen oxides, carbon monoxide and total suspended particulate emissions for 1985, the expected peak emission year for these pollutants based on the mean resource estimate. These represent the emissions that may be associated with the development phase of OCS activity.

iii. Maximum Daily Emissions

Included in Tables V-34 and V-35 are maximum estimated daily emissions. Production and processing related emissions are assumed to be steady state; however, emissions from support activity and tanker and barge operations would vary with time. The daily emissions are presented to give a better perspective on the emissions associated with support activity, and tanker and barge operations.

iv. Comparison of Projected Regional Emissions

Projected 1985 emissions associated with the Bay Area Air Quality Management District (BAAQMD) are presented in Table V-36. The projected emissions from the BAAQMD were chosen for comparison with estimated peak annual emissions occurring from proposed Lease Sale No. 53 OCS activity in the Bodega zone because of the proximity of the Bodega zone to the BAAQMD. The 1985 projections were chosen for comparison because 1985 is the year closest to the estimated peak emission years of 1985 and 1987 for which emission projections exist.

The emissions in the BAAQMD are expected to occur from a wide variety of sources. Major among these would be vehicular emissions and emissions from industrial, commercial and residential combustion of fuel.

Presented in Table V-37 are comparisons of the estimated peak emissions from proposed OCS activity in the Bodega zone and the projected 1985 emissions from the BAAQMD. Because of the large population and high amount of industry in the BAAQMD, the regional emissions from the area are high. Since the Bodega zone is expected to be the smallest of the five lease tracts and Lease Sale No. 53 activity in the area is expected to be relatively low, the estimated emissions from OCS activity in the Bodega zone would be small in comparison to the regional emissions from the BAAQMD.

d. Santa Cruz

i. Total Annual Emissions

The annual emissions expected from oil and gas development in the Santa Cruz zone due to Lease Sale 53 are presented in Tables V-38 -V-42.

a) Offshore Emissions

Exploratory and delineation drilling would be the first step in developing the Santa Cruz zone. The pollutants emitted in the greatest quantity during this period, 1981 through 1984, would be nitrogen oxides. Drilling and supportive

activities would result in nitrogen oxide emissions of 100 to 300 tons per year, depending upon the level of activity.

Development would begin in 1985 and production would start the following year. According to the production level predicted by USGS for the mean resource recovery estimate, four platforms would be installed at the rate of one per year through 1988. Construction of a gas pipeline would be expected to take 73 days. Construction of an oil pipeline, which would be necessary if Transportation Scenario 1 or 1A is selected, would take another 45 days. The power, barges, tugboats and supportive activities required both offshore and onshore by the various construction operations would result in nitrogen oxide, carbon monoxide and total suspended particulate emission increases in 1986 of approximately five times the pollutant levels expected during 1984. These emissions would be expected to remain at elevated levels through 1988, when the last 36 of 115 wells would be drilled. In fact, as production activities--and production related emissions--increase, the total emissions of nitrogen oxides, carbon monoxide and total suspended particulates increase, reaching a maximum in 1988.

Hydrocarbon and sulfur oxide emissions are more closely associated with production activities than with construction activities. Therefore, the greatest quantities of these pollutants would be emitted in 1990, the year of peak production. Gas processing is the largest single hydrocarbon source and the second largest source of sulfur oxides that year. This is of special importance because this source could be located either onshore (Transportation Scenario 1A) or offshore (all other proposed scenarios), and may generate up to 1,350 tons of hydrocarbons and 60 tons of sulfur oxides in 1990. However, gas processing emission factors are based on existing onshore facilities and may be overstated.

The combustion of diesel fuel to produce power offshore would be the principal source of sulfur oxides from 1987 onward, whereas platform installation would be the primary source in 1985 and 1986.

b) Transportation Emissions

The crude oil from Santa Cruz zone could be transported in one of three ways: 1) by pipeline, first to shore and then overland to San Francisco area refineries (according to BLM Transportation Scenario 1 or 1A); 2) by barge to San Francisco refineries (BLM Transportation Scenario 2); or 3) by tanker to the Gulf Coast (BLM Transportation Scenario 3).

The sizes of ships to be used and the frequency of their trips have been estimated and summarized in Tables A-42, A-47, A-48 and A-49 in Appendix A. Hydrocarbon losses during loading would be the most significant emission involving ships in Transportation Scenarios 2 and 3.

Nitrogen oxides from tugs towing barges or sulfur oxides from the tankers in transit would also be emitted in large quantities. Because ships are mobile emission sources the pollutants would be dispersed over a rather large area. In the footnotes for Tables A-58 - A-61 in Appendix A, which decribe emissions on a per visit basis, an account is given of the time a ship spends traveling along the coast on a county by county basis.

Table V-34. MAXIMUM DAILY AND HOURLY EMISSIONS ASSOCIATED WITH LEASE SALE NO. 53 OIL AND GAS DEVELOPMENT - BODEGA ZONE (PEAK PRODUCTION YEAR - 1987; MEAN RESOURCE ESTIMATE)

Source	Emissions lbs/day (lbs/hr) HC	NO_x	SO_x	CO	TSP
OFFSHORE SOURCES COMMON TO ALL SCENARIOS					
Development Drilling[1]	12 (0.5)	136 (6)	72 (3)	32 (1)	10 (0.4)
Support Activity[2]	31 (3)	1,351 (137)	93 (9)	203 (21)	59 (6)
Power Generation[3]	32 (1)	342 (14)	184 (8)	73 (3)	32 (1)
Evaporative Losses[4]	332 (14)	--	--	--	--
ONSHORE SOURCES COMMON TO ALL SCENARIOS					
Miscellaneous[5]	14 (0.6)	23 (1)	3 (0.1)	216 (9)	6 (3)
Subtotal	421 (19)	1,853 (15)	352 (20)	534 (34)	107 (1)
SCENARIOS 1,1A,2					
Offshore Sources					
Tankers at OS&T[6]	1,831 (609)	68 (17)	5 (1)	10 (3)	3 (0.8)
Tankers near Platform[7]	4	17	1	3	0.8
Tankers in Sea Passage[8]	12	47	3	7	2
Tankers in Harbor Area[9]	12	47	3	7	2
Onshore Sources					
Tankers in Port [10]	27	218	15	34	10
Subtotal	1,886 (609)	397 (17)	28 (1)	61 (3)	18 (0.8)
TOTAL (Scenarios 1,1A, and 2)	2,307 (628)	2,249 (175)	380 (21)	595 (37)	125 (12)

Table V-34 (continued)

Source	Emissions lbs/day (lbs/hr) HC	NO_x	SO_x	CO	TSP
SCENARIO 3					
Offshore Sources					
Tankers at OS&T[11]	7,137 (793)	114 (8)	756 (50)	1 (0.1)	45 (3)
Tankers near Platform[12]	12	192	1,220	2	73
Tankers in Sea Passage[13]	3	44	329	0.6	20
Subtotal	7,152 (793)	350 (8)	2,305 (50)	4 (0.1)	138 (3)
TOTAL (Scenario 3)	7,573 (812)	2,202 (166)	2,657 (70)	538 (34)	245 (14)

1. Based on 2 wells expected to be drilled simultaneously and emissions per day - per well drilled presented in Table A-22in Appendix A.

2. Daily emissions based on Tables A-23 and A-24 presented in Appendix A. Hour emissions assume 1 crew boat and 2 supply boats operating simultaneously and emission factors presented in Table A-1 of Appendix A.

3. Based on emission factors for diesel fired turbines presented in Table A-1 of Appendix A and production level presented in Table V-1.

4. Based on evaporative emission factors presented in Appendix A in Table A-1 and production level presented in Table V-1.

5. Includes workers' vehicles and helicopter. Based on emissions presented in Tables A-23 and A-24 in Appendix A.

6. Based on 3 hours of loading and 1 hour of hoteling. Loading would produce the maximum hourly emissions.

7. Based on 1 hour of maneuvering about the platform.

8. Based on 2.75 hours of sea passage.

Table V-34 (continued)

9. Based on 2.75 hours of maneuvering at reduced speed landward of the Golden Gate Bridge.

10. Based on 7.5 hours of offloading and 5 hours of hoteling and refueling. The maximum hour of emissions would occur during refueling.

11. Based on 9 hours of loading, 5 hours of discharging ballast and 2 hours of hoteling. Loading would produce the maximum hourly emissions.

12. Based on 3 hours of maneuvering near the platform.

13. Based on 5 hours of sea passage.

Table V-35. MAXIMUM DAILY AND HOURLY NITROGEN OXIDE, CARBON MONOXIDE AND TOTAL SUSPENDED PARTICULATE EMISSIONS ASSOCIATED WITH LEASE SALE NO. 53 OCS DEVELOPMENT - BODEGA ZONE

(MEAN RESOURCE ESTIMATE, PEAK EMISSION YEAR - 1985)

	Emissions lbs/day (lbs/hr)		
Source/Activity	NO_x	CO	TSP
OFFSHORE SOURCES COMMON TO ALL SCENARIOS			
Platform Installation[1]	4,939 (240)	809 (39)	244 (12)
Support Activity[2]	884 (137)	133 (11)	38 (6)
Subtotal	5,823 (377)	942 (50)	282 (18)
ONSHORE SOURCES COMMON TO ALL SCENARIOS			
Miscellaneous[3]	17 (0.7)	160 (7)	5 (0.2)
TOTAL	5,840 (378)	1,102 (57)	287 (18)

1. Based on 1 platform expected to be installed as presented in Table V-3 and emissions per day per platform installed presented in Table A-20 in Appendix A.

2. Includes support for platform installation. Based on Table A-20 in Appendix A.

3. Includes workers' vehicles and helicopter. Based on emissions presented in Table A-20 in Appendix A.

Table V-36 PROJECTED 1985 EMISSIONS FOR THE BAY AREA AIR QUALITY MANAGEMENT DISTRICT[1]

Source	Emissions - tons/year (% of total emissions)				
	HC[2]	NO_x	SO_x	CO	TSP
Vehicular[3]	77,745(27%)	92,710(37%)	9,125(6%)	1,032,585(84%)	12,811(18%)
Petroleum[4]	43,070(15%)	5,475(2%)	24,820(16%)	--	1,606(2%)
Combustion of Fuels [5]	4,380(1%)	117,165(47%)	78,110(49%)	7,665(1%)	12,595(18%)
Organic Solvents	125,925(43%)	--	--	--	--
Other Stationary[6]	14,235(5%)	2,555(1%)	35,040(22%)	45,260(4%)	36,464(52%)
Other Mobile[7]	25,550(9%)	33,945(13%)	11,680(7%)	143,445(11%)	6,460(10%)
Total	290,905(100%)	252,580(100%)	158,775(100%)	1,228,955(100%)	69,936(100%)

1. Source: Association of Bay Area Governments, 1979 Bay Area Air Quality Plan.
2. Refers to total hydrocarbon emissions.
3. Includes light duty autos and other motor vehicles.
4. Includes refining and distribution.
5. Includes combustion of natural gas, oil and coal.
6. Includes waste burning, and industrial and commercial processes and combustion.
7. Includes offroad mobile sources and aircraft.

Table V-37 COMPARISON OF EMISSIONS ASSOCIATED WITH LEASE SALE NO. 53 ACTIVITIES IN THE BODEGA ZONE WITH REGIONAL EMISSION INVENTORY FOR THE BAY AREA AIR QUALITY MANAGEMENT DISTRICT

Pollutant	Peak Emission Year	Tons Per Year[1] (Percentage of Emissions Associated with Lease Sale No. 53 Activities to Regional Emission Inventory)[2,3] Transportation Scenario 1	Transportation Scenario 1-A	Transportation Scenario 2	Transportation Scenario 3
Total Hydrocarbons	1987	194(0.07%)	194(0.07%)	194(0.07%)	140(0.5%)
Nitrogen Oxides	1985	730(0.3%)	730(0.3%)	730(0.3%)	730(0.3%)
Sulfur Oxides	1987	50(0.05%)	50(0.05%)	50(0.03%)	66(0.05%)
Carbon Monoxide	1985	135(0.01%)	135(0.01%)	135(0.01%)	135(0.01%)
Total Suspended Particulate	1985	36(0.05%)	36(0.05%)	36(0.05%)	36(0.05%)

1. Based on the USGS mean resource estimate.
2. Emissions associated with Lease Sale No. 53 OCS activity in the Bodega Zone have been compared to projected 1985 onshore emissions for the Bay Area Air Quality Management District (BAAQMD). Emissions for the BAAQMD have been obtained from the Bay Area Air Quality Plan (Association of Bay Area Governments, 1979).
3. Portions of estimated emissions associated with Lease Sale No. 53 OCS activity in the Bodega Zone occur from mobile sources outside of zone.

Table V-38. ANNUAL HYDROCARBON EMISSIONS ASSOCIATED WITH LEASE SALE NO. 53 OCS OIL AND GAS DEVELOPMENT - SANTA CRUZ ZONE (MEAN RESOURCE ESTIMATE) (tons/year)

	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1995	2000	2005
OFFSHORE OPERATIONS COMMON TO ALL SCENARIOS													
Exploratory/Delineation Drilling[1]	1	4	4	3	1	--	--	--	--	--	--	--	--
Platform Installation[2]	--	--	--	--	23	23	23	23	--	--	--	--	--
Pipeline Installation (73 days)[3]	--	--	--	--	8	--	--	--	--	--	--	--	--
Development Drilling[4]	--	--	--	--	--	0.5	2	2	2	2	--	--	--
Supportive Activity[5]	1	3	4	3	4	6	9	11	7	6	4	4	4
Production Power Generation[6]	--	--	--	--	--	1	8	16	23	27	15	8	4
Evaporative Losses[7]	--	--	--	--	--	14	86	178	258	302	170	90	48
(Subtotal - Emissions from Common Offshore Operations)	2	7	8	6	36	44	128	230	290	337	189	102	56
A. SCENARIO 1													
Onshore Emissions													
Pipeline Installation[8]	--	--	--	--	5	--	--	--	--	--	--	--	--
Miscellaneous[9]	0.4	1	1	0.6	2	2	5	6	3	3	2	2	2
Offshore Emissions													
Pipeline Construction (45 days)[3]	--	--	--	--	6	--	--	--	--	--	--	--	--
Additional Support Activity[5]	--	--	--	--	0.4	--	--	--	--	--	--	--	--
Power Generation (Oil Pumping)[10]	--	--	--	--	--	0.2	1	3	4	5	3	1	0.8
Evaporative (From Oil Pipeline)[7]	--	--	--	--	--	2	12	25	37	43	20	13	7
Gas Processing[11]	--	--	--	--	--	61	387	805	1169	1364	767	410	218
Oil Processing[12]	--	--	--	--	--	Neg.	0.2	0.4	0.6	0.7	0.4	0.2	0.1
Subtotal	0.4	1	1	0.6	13	65	405	839	1214	1416	792	426	228
TOTAL (Scenario 1)	2	8	9	7	49	110	533	1069	1504	1753	981	528	284

Table V-38 (continued)

	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1995	2000	2005
B. SCENARIO 1A:													
Onshore Emissions													
Pipeline Installation[8]	--	--	--	--	5	--	--	--	--	--	--	--	--
Miscellaneous[9]	0.4	1	1	0.6	2	2	5	6	3	3	2	2	2
Evaporative (From Storage Tanks)[13]	--	--	--	--	--	1	2	3	3	4	3	2	2
Gas Processing[11]	--	--	--	--	--	61	387	805	1169	1364	767	410	218
Oil Processing[12]	--	--	--	--	--	Neg.	0.2	0.4	0.6	0.7	0.4	0.2	0.1
Offshore Emissions													
Pipeline Installation[3]	--	--	--	--	6	--	--	--	--	--	--	--	--
Additional Support Activity[5]	--	--	--	--	0.4	--	--	--	--	--	--	--	--
Power Generation (Oil Pumping)[10]	--	--	--	--	--	0.2	1	3	4	5	3	1	0.8
Evaporative Losses (From Oil Pipeline)[7]	--	--	--	--	--	2	12	25	37	43	20	13	7
Subtotal	0.4	1	1	0.6	13	66	407	842	1217	1420	795	428	230
TOTAL (Scenario 1A)	2	8	9	7	49	111	535	1072	1507	1757	984	530	286
C. SCENARIO 2:													
Onshore Emissions													
Pipeline Installation[8]	--	--	--	--	0.5	--	--	--	--	--	--	--	--
Miscellaneous[9]	0.4	1	1	0.6	2	2	5	6	3	3	2	2	2
Tankers In Port[14]	--	--	--	--	--	0.4	2	5	8	9	5	3	1
Offshore Emissions													
Gas Processing[11]	--	--	--	--	--	61	387	805	1169	1364	767	410	218
Oil Processing[12]	--	--	--	--	--	Neg.	0.2	0.4	0.6	0.7	0.4	0.2	0.1
Tankers at OS&T[15]	--	--	--	--	--	37	214	447	649	753	422	226	122
Tankers in Transit[16]	--	--	--	--	--	1	6	13	19	23	13	7	4
Subtotal	0.4	1	1	0.6	2	102	615	1277	1848	2153	1209	648	347
TOTAL (Scenario 2)	2	8	9	7	38	146	743	1507	2138	2490	1398	750	403

Table V-38 (continued)

	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1995	2000	2005
D. SCENARIO 3													
Onshore Emissions													
Pipeline Construction[8]	--	--	--	--	0.5	--	--	--	--	--	--	--	--
Miscellaneous[9]	0.4	1	1	0.6	2	2	5	6	3	3	2	2	2
Offshore Emissions													
Gas Processing[11]	--	--	--	--	--	61	387	805	1169	1364	767	410	218
Oil Processing[12]	--	--	--	--	--	Neg.	0.2	0.4	0.6	0.7	0.4	0.2	0.1
Tankers at OS&T[17]	--	--	--	--	--	14	75	150	218	252	143	75	41
Tankers In Transit[18]	--	--	--	--	--	0.01	0.1	0.2	0.2	0.3	0.2	0.1	0.04
Subtotal	0.4	1	1	0.6	2	77	467	962	1391	1620	913	487	261
TOTAL (Scenario 3)	2	8	9	7	38	122	595	1192	1681	1957	1102	589	317

1. Based on number of wells expected to be drilled as presented in Table V-2 and emissions per day per well drilled as presented in Table A-26 in Appendix A.

2. Based on number of platforms expected to be installed as presented in Table V-3 and emissions per day per platform installed as presented in Table A-27 in Appendix A.

3. Based on the length of pipeline expected to be installed as presented in Table V-4 and emissions per day for subsea pipeline installation as presented in Table A-28 in Appendix A.

4. Based on number of wells expected to be drilled as presented in Table V-2 and emissions per day per well drilled as presented in Table A-29 in Appendix A.

5. Based on emissions presented in Tables A-26, A-27, A-28, A-30 and A-31 in Appendix A.

Table V-38 (continued)

6. Based on emission factors for diesel-fired turbines presented in Table A-1 in Appendix A, power usage factors presented in Table A-3 in Appendix A and production level presented in Table V-1.

7. Based on evaporative emission factors presented in Table A-1 in Appendix A and production level presented in Table V-1.

8. See Table A-40 in Appendix A for annual emissions associated with overland pipeline construction.

9. Includes workers' vehicles and helicopter. Based on emissions presented in Tables A-26, A-27, A-28, A-30, and A-31 in Appendix A.

10. Based on emission factors for diesel fired turbines presented in Table A-1 in Appendix A, 40 percent of power usage for electricity presented in Table A-3 of Appendix A and production level presented in Table V-1.

11. Based on emission factors for gas processing presented in Table A-1 in Appendix A and production level presented in Table V-1.

12. Based on emission factors for natural gas combustion presented in Table A-1 in Appendix A, an average heat requirement of 15,000 Btu/bbl (Energy Resources Co., 1977) and production level presented in Table V-1.

13. Based on equations and variables presented in Table A-41 in Appendix A and assumptions stated in Section V.D.1.

14. Emissions would occur while the tanker or barge is docked at San Francisco. Based upon per visit emissions given in Table A-58 in Appendix A and the expected number of voyages required as presented in Table A-47 in Appendix A.

15. Emissions would occur while the tanker or barge is docked at the OS&T. Based upon per visit emissions given in Table A-58 in Appendix A and the expected number of voyages required as presented in Table A-47 in Appendix A.

16. Emissions would occur while the tanker is en route between the OS&T and the dock in San Francisco. Based upon per visit emissions given in Table A-58 in Appendix A and the expected number of voyages required as presented in Table A-47 in Appendix A.

17. Emissions would occur while the tanker is docked at the OS&T. Based upon per visit emissions given in Table A-61 in Appendix A and the expected number of voyages required as presented in Table A-47 in Appendix A.

18. Emissions would occur while the tanker is traveling in waters between the zone and the southern Monterey County Border. Based upon per visit emissions given in Table A-61 in Appendix A and the expected number of voyages as presented in Table A-47 in Appendix A.

Table V-39 ANNUAL NITROGEN OXIDE EMISSIONS ASSOCIATED WITH LEASE SALE NO. 53 OCS OIL AND GAS DEVELOPMENT - SANTA CRUZ ZONE (MEAN RESOURCE ESTIMATE)

(tons/year)

	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1995	2000	2005
OFFSHORE OPERATIONS COMMON TO ALL SCENARIOS													
Exploratory/Delineation Drilling[1]	37	107	132	87	35	--	--	--	--	--	--	--	--
Platform Installation[2]	--	--	--	--	631	631	631	631	--	--	--	--	--
Pipeline Installation (73 days)[3]	--	--	--	--	220	--	--	--	--	--	--	--	--
Development Drilling[4]	--	--	--	--	--	9	21	29	29	21	--	--	--
Supportive Activity[5]	47	136	167	110	144	201	353	446	335	268	192	192	192
Production Power Generation[6]	--	--	--	--	--	10	62	128	185	216	119	64	35
(Subtotal - Emissions from Common Offshore Operations)	84	243	299	197	1,030	849	1,067	1,234	549	505	311	256	227
A. SCENARIO 1													
Onshore Emissions													
Pipeline Installation[7]	--	--	--	--	83	--	--	--	--	--	--	--	--
Miscellaneous[8]	0.6	2	2	1	4	3	7	9	6	5	3	3	3
Offshore Emissions													
Pipeline Installation (45 days)[3]	--	--	--	--	150	--	--	--	--	--	--	--	--
Additional Support Activity[5]	--	--	--	--	16	--	--	--	--	--	--	--	--
Oil Processing[9]	--	--	--	--	--	0.4	3	5	8	9	5	3	1
Power Generation (Gas Compression)[18]	--	--	--	--	--	3	18	38	56	65	37	20	10
Power Generation (Oil Pumping)[11]	--	--	--	--	--	2	13	28	40	47	26	14	7
Subtotal	0.6	2	2	1	253	8	41	80	110	126	71	40	21
TOTAL (Scenario 1)	85	245	301	198	1283	857	1108	1314	659	631	382	296	248

Table V-39 (continued)

	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1995	2000	2005
B. SCENARIO 1A:													
Onshore Emissions													
Pipeline Installation[7]	--	--	--	--	83	--	--	--	--	--	--	--	--
Miscellaneous[8]	0.6	2	2	1	4	3	7	9	6	5	3	3	3
Power Generation (Gas Compression)[10]	--	--	--	--	--	3	18	38	56	65	37	20	10
Oil Processing[9]						0.4	3	5	8	9	5	3	1
Offshore Emissions													
Pipeline Installation[3]	--	--	--	--	150	--	--	--	--	--	--	--	--
Additional Support Activity[5]	--	--	--	--	16	--	--	--	--	--	--	--	--
Power Generation (Oil Pumping)[11]	--	--	--	--	--	2	13	28	40	47	26	14	7
Subtotal	0.6	2	2	1	253	8	41	80	110	126	71	40	21
TOTAL (Scenario 1A)	85	245	301	198	1283	857	1108	1314	654	631	382	296	248
C. SCENARIO 2:													
Onshore Emissions													
Pipeline Installation[7]	--	--	--	--	6	--	--	--	--	--	--	--	--
Miscellaneous[8]	0.6	2	2	1	3	3	7	9	6	5	3	3	3
Tankers In Port[12]	--	--	--	--	--	2	12	24	35	41	23	12	7
Offshore Emissions													
Power Generation (Gas Compression)[10]	--	--	--	--	--	3	18	38	56	65	37	20	10
Oil Processing[9]	--	--	--	--	--	0.4	3	5	8	9	5	3	1
Tankers at OS&T[13]	--	--	--	--	--	1	7	14	20	24	13	7	4
Tankers In Transit[14]	--	--	--	--	--	2	11	22	32	37	21	11	6
Subtotal	0.6	2	2	1	9	11	58	112	157	181	102	56	31
TOTAL (Scenario 2)	85	245	301	198	1039	860	1125	1346	706	686	413	312	258

Table V-39 (continued)

	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1995	2000	2005
D. SCENARIO 3													
Onshore Emissions													
Pipeline installation[7]	--	--	--	--	6	--	--	--	--	--	--	--	--
Miscellaneous[8]	0.6	2	2	1	3	3	7	9	6	5	3	3	3
Offshore Emissions													
Power Generation (Gas Compression)[10]	--	--	--	--	--	3	18	38	56	65	37	20	10
Oil Processing[9]	--	--	--	--	--	0.4	3	5	8	9	5	3	1
Tankers at OS&T[15]	--	--	--	--	--	0.2	1	3	4	4	2	1	0.7
Tankers In Transit[16]	--	--	--	--	--	0.2	1	3	4	4	2	1	0.7
Subtotal	0.6	2	2	1	9	7	30	58	78	87	49	28	15
TOTAL (Scenario 3)	85	245	301	198	1039	856	1097	1292	627	592	360	284	242

1. Based on number of wells expected to be drilled as presented in Table V-2 and emissions per day per well drilled as presented in Table A-26 in Appendix A.

2. Based on number of platforms expected to be installed as presented in Table V-3 and emissions per day per platform installed as presented in Table A-27 in Appendix A.

3. Based on the length of pipeline expected to be installed as presented in Table V-4 and emissions per day for subsea pipeline installation as presented in Table A-28 in Appendix A.

4. Based on number of wells expected to be drilled as presented in Table V-2 snd emissions per day per well drilled as presented in Table A-29 in Appendix A.

5. Based on emissions presented in Tables A-26, A-27, A-28, A-30 and A-31 in Appendix A.

6. Based on emission factors for diesel fired turbines presented in Table A-1 in Appendix A, power usage factors presented in Table A-3 in Appendix A and production level presented in Table V-1.

7. See Table A-40 in Appendix A for annual emissions associated with overland pipeline instsllation.

8. Includes workers' vehicles and helicopter. Based on emissions presented in Tables A-26, A-27, A-28, A-30 and A-31 in Appendix A.

Table V-39 (continued)

9. Based on emission factors for natural gas combustion presented in Table A-1 in Appendix A, an average heat requirement of 15,000 Btu/bbl (Energy Resources Co., 1977) and production level presented in Table V-1.

10. Based on emission factors for gas processing presented in Table A-1 in Appendix A and production level presented in Table V-1.

11. Based on emission factors for diesel fired turbines presented in Table A-1 in Appendix A, 40 percent of power usage for electricity presented in Table A-3 of Appendix A and production level presented in Table V-1.

12. Emissions would occur while the tanker or barge is docked at San Francisco. Based on per visit emissions given in Table A-58 in Appendix A and the expected number of voyages required as presented in Table A-47 in Appendix A.

13. Emissions would occur while the tanker or barge is docked at the OS&T. Based upon per visit emissions given in Table A-58 in Appendix A and the expected number of voyages required as presented in Table A-47 in Appendix A.

14. Emissions would occur while the tanker or barge is en route between the OS&T and the dock in San Francisco. Based upon per visit emissions given in Table A-58 in Appendix A and the expected number of voyages required as presented in Table A-47 in Appendix A.

15. Emissions would occur while the tanker is docked at the OS&T. Based upon per visit emissions given in Table A-61 in Appendix A and the expected number of voyages required as presented in Table A-47 in Appendix A.

16. Emissions would occur while the tanker is traveling in waters between the zone and the southern Monterey County border. Based upon per visit emissions given in Table A-61 in Appendix A and the expected number of voyages required as presented in Table A-47 in Appendix A.

Table V-40. ANNUAL SULFUR OXIDE EMISSIONS ASSOCIATED WITH LEASE SALE NO. 53 OCS OIL AND GAS DEVELOPMENT - SANTA CRUZ ZONE
(MEAN RESOURCE ESTIMATE)
(tons/year)

	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1995	2000	2005
OFFSHORE OPERATIONS COMMON TO ALL SCENARIOS													
Exploratory/Delineation Drilling[1]	3	7	9	6	2	--	--	--	--	--	--	--	--
Platform Installation[2]	--	--	--	--	42	42	42	42	--	--	--	--	--
Pipeline Installation (73 days)[3]	--	--	--	--	15	--	--	--	--	--	--	--	--
Development Drilling[4]	--	--	--	--	--	3	11	15	15	11	--	--	--
Supportive Activity[5]	3	9	11	8	10	14	24	30	23	18	13	13	13
Production Power Generation[6]	--	--	--	--	--	7	43	90	130	152	85	46	24
(Subtotal - Emissions from Common Offshore Operations)	6	16	20	14	69	66	120	177	168	181	98	59	37
A. SCENARIOS 1 AND 2:													
Onshore Emissions													
Pipeline Installation[7]	--	--	--	--	6	--	--	--	--	--	--	--	--
Miscellaneous[8]	0.1	0.4	0.5	0.3	0.4	0.5	1	1	1	0.8	0.6	0.6	0.6
Offshore Emissions													
Pipeline Installation[3]	--	--	--	--	10	--	--	--	--	--	--	--	--
Additional Support Activity[5]	--	--	--	--	1	--	--	--	--	--	--	--	--
Power Generation (Oil Pumping)[9]	--	--	--	--	--	1	7	15	21	25	14	7	4
Gas Processing[10]	--	--	--	--	--	3	20	41	59	69	39	21	11
Subtotal	0.1	0.4	0.5	0.3	17	4	28	57	81	95	54	29	16
TOTAL (Scenario 1)	6	16	20	14	86	70	148	234	249	276	152	88	53

Table V-40 (continued)

	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1995	2000	2005
B. SCENARIO 1A:													
Onshore Emissions													
Pipeline Installation[7]	--	--	--	--	6	--	--	--	--	--	--	--	--
Miscellaneous[8]	0.1	0.4	0.5	0.3	0.4	0.5	1	1	1	0.8	0.6	0.6	0.6
Gas Processing[10]	--	--	--	--	--	3	20	41	59	69	39	21	11
Offshore Emissions													
Pipeline Installation[3]	--	--	--	--	10	--	--	--	--	--	--	--	--
Additional Support Activity[5]	--	--	--	--	1	--	--	--	--	--	--	--	--
Power Generation (Oil Pumping)[9]	--	--	--	--	--	1	7	15	21	25	14	7	4
Subtotal	0.1	0.4	0.5	0.3	17	4	28	57	81	95	54	29	16
TOTAL (Scenario 1A)	6	16	20	14	86	70	148	234	249	276	152	88	53
C. SCENARIO 2:													
Onshore Emissions													
Pipeline Installation[7]	--	--	--	--	0.5	--	--	--	--	--	--	--	--
Miscellaneous[8]	0.1	0.4	0.5	0.3	0.4	0.5	1	1	1	0.8	0.6	0.6	0.6
Tankers In Port[11]	--	--	--	--	--	0.1	0.8	2	2	3	2	0.9	0.5
Offshore Emissions													
Gas Processing[10]	--	--	--	--	--	3	20	41	59	69	39	21	11
Tankers at OS&T[12]	--	--	--	--	--	0.1	0.5	1	1	2	0.9	0.5	0.3
Tankers in Transit[13]	--	--	--	--	--	0.1	0.7	1	2	3	1	0.8	0.4
Subtotal	0.1	0.4	0.5	0.3	0.9	4	23	46	66	77	43	24	13
TOTAL (Scenario 2)	6	16	20	14	70	70	143	223	234	258	141	83	50

Table V-40 (continued)

	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1995	2000	2005
D. SCENARIO 3													
Onshore Emissions													
Pipeline Installation[7]	--	--	--	--	0.5	--	--	--	--	--	--	--	--
Miscellaneous[8]	0.1	0.4	0.5	0.3	0.4	0.5	1	1	1	0.8	0.6	0.6	0.6
Offshore Emissions													
Gas Processing[10]	--	--	--	--	--	3	20	41	59	69	39	21	11
Tankers at OS&T[14]	--	--	--	--	--	2	8	17	24	28	16	8	5
Tankers In Transit[15]	--	--	--	--	--	2	8	17	24	28	16	8	5
Subtotal	0.1	0.4	0.5	0.3	0.9	7	37	76	108	126	72	38	22
TOTAL (SCENARIO 3)	6	16	20	14	70	73	157	253	276	307	170	97	59

1. Based on number of wells expected to be drilled as presented in Table V-2 and emissions per day per well drilled as presented in Table A-26 in Appendix A.

2. Based on number of platforms expected to be installed as presented in Table V-3 and emissions per day per platform installed as presented in Table A-27 in Appendix A.

3. Based on the length of pipeline expected to be installed as presented in Table V-4 and emissions per day for subsea pipeline installation as presented in Table A-28 in Appendix A.

4. Based on number of wells expected to be drilled as presented in Table V-2 and emissions per day per well drilled as presented in Table A-29 in Appendix A.

5. Based on emissions presented in Tables A-26, A-27, A-28, A-30 and A-31 in Appendix A.

6. Based on emission factors for diesel fired turbines presented in Table A-1 in Appendix A, power usage factors presented in Table V-3 in Appendix A and production level presented in Table V-1.

7. See Table A-40 in Appendix A for annual emissions associated with overland pipeline installation.

Table A-40 (continued)

8. Includes workers' vehicles and helicopter. Based on emissions presented in Tables A-26, A-27, A-28, A-30 and A-31 in Appendix A.

9. Based on emission factors for diesel fired turbines presented in Table A-1 in Appendix A, 40 percent of power usage for electricity presented in Table A-3 of Appendix A and production level presented in Table V-1.

10. Based on emission factors for gas processing presented in Table A-1 in Appendix A and production level presented in Table V-1.

11. Emissions would occur while the tanker or barge is docked at San Francisco. Based on per visit emissions given in Table V-58 in Appendix A and the expected number of voyages required as presented in Table A-47 in Appendix A.

12. Emissions would occur while the tanker or barge is docked at the OS&T. Based upon per visit emissions given in Table A-58 in Appendix A and the expected number of voyages required as presented in Table A-47 in Appendix A.

13. Emissions would occur while the tanker or barge is en route between the OS&T and the dock in San Francisco. Based upon per visit emissions given in Table A-58 in Appendix A and the expected number of voyages required as presented in Table A-47 in Appendix A.

14. Emissions would occur while the tanker is docked at the OS&T. Based upon per visit emissions given in Table A-61 in Appendix A and the expected number of voyages required as presented in Table A-47 in Appendix A.

15. Emissions occur while the tanker is traveling in waters between the zone and the southern Monterey County border. Based upon per visit emissions given in Table A-61 in Appendix A and the expected number of voyages required as presented in Table A-47 in Appendix A.

Table V-41. ANNUAL CARBON MONOXIDE EMISSIONS ASSOCIATED WITH LEASE SALE NO. 53 OCS OIL AND GAS DEVELOPMENT - SANTA CRUZ ZONE
(MEAN RESOURCE ESTIMATE)
(tons/year)

	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1995	2000	2005
OFFSHORE OPERATIONS COMMON TO ALL SCENARIOS													
Exploratory/Delineation Drilling[1]	5	16	19	13	5	--	--	--	--	--	--	--	--
Platform Installation[2]	--	--	--	--	102	102	102	102	--	--	--	--	--
Pipeline Installation (73 days)[3]	--	--	--	--	36	--	--	--	--	--	--	--	--
Development Drilling[4]	--	--	--	--	--	2	5	7	7	5	--	--	--
Supportive Activity[5]	7	20	25	16	23	30	53	67	43	41	29	29	29
Production Power Generation[6]	--	--	--	--	--	2	17	35	51	60	34	18	9
(Subtotal - Emissions from Common Offshore Operations)	12	36	44	29	166	136	177	211	101	106	63	47	38
A. SCENARIO 1													
Onshore Emissions													
Pipeline Installation[7]	--	--	--	--	20	--	--	--	--	--	--	--	--
Miscellaneous[8]	6	17	21	14	39	39	74	92	62	56	30	30	30
Offshore Emissions													
Pipeline Installation (45 days)[3]	--	--	--	--	25	--	--	--	--	--	--	--	--
Additional Support Activity[5]	--	--	--	--	2	--	--	--	--	--	--	--	--
Power Generation (Oil Pumping)[9]	--	--	--	--	--	0.4	3	6	8	10	6	3	2
Oil Processing[10]	--	--	--	--	--	Neg.	0.5	1	2	2	1	0.5	0.3
Subtotal	6	17	21	14	86	39	77	99	72	68	37	33	32
TOTAL (Scenario 1)	18	53	65	43	252	175	254	310	173	174	100	80	70

Table V-41 (continued)

	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1995	2000	2005
B. SCENARIO 1A:													
Onshore Emissions													
Pipeline Installation[7]	--	--	--	--	20	--	--	--	--	--	--	--	--
Miscellaneous[8]	6	17	21	14	39	39	74	92	62	56	30	30	30
Oil Processing[10]	--	--	--	--	--	Neg.	0.5	1	2	2	1	0.5	0.3
Offshore Emissions													
Pipeline Installation[3]	--	--	--	--	25	--	--	--	--	--	--	--	--
Additional Support Activity[5]	--	--	--	--	2	--	--	--	--	--	--	--	--
Power Generation (Oil Pumping)[9]	--	--	--	--	--	0.4	3	6	8	10	6	3	2
Subtotal	6	17	21	14	86	39	77	99	72	68	37	33	32
TOTAL (Scenario 1A)	18	53	65	43	252	175	254	310	173	174	100	80	70
C. SCENARIO 2:													
Onshore Emissions													
Pipeline Installation[7]	--	--	--	--	1	--	--	--	--	--	--	--	--
Miscellaneous[8]	6	17	21	14	32	39	74	92	62	56	30	30	30
Tankers In Port[11]	--	--	--	--	--	0.3	2	4	5	6	3		1
Offshore Emissions													
Oil Processing[10]	--	--	--	--	--	Neg.	0.5	1	2	2	1	0.5	0.3
Tankers at OS&T[12]	--	--	--	--	--	0.2	1	2	3	4	2	1	0.6
Tankers in Transit[13]	--	--	--	--	--	0.3	2	3	5	5	3	2	0.9
Subtotal	6	17	21	14	33	40	79	102	77	73	40	35	33
TOTAL (Scenario 2)	18	53	65	43	199	176	256	313	178	179	103	82	71

Table V-41 (continued)

	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1995	2000	2005
D. SCENARIO 3													
Onshore Emissions													
Pipeline Installation[7]	--	--	--	--	1	--	--	--	--	--	--	--	--
Miscellaneous[8]	6	17	21	14	32	39	74	92	62	56	30	30	30
Offshore Emissions													
Oil Processing[10]	--	--	--	--	--	Neg.	0.5	1	2	2	1	0.5	0.3
Tankers at OS&T[14]	--	--	--	--	--	Neg.	0.02	0.03	0.05	0.05	0.03	0.02	Neg.
Tankers in Transit[15]	--	--	--	--	--	Neg.	0.02	0.03	0.05	0.05	0.03	0.02	Neg.
Subtotal	6	17	21	14	33	39	74	93	64	58	31	30	30
TOTAL (Scenario 3)	18	53	65	43	198	175	251	304	165	164	94	77	68

1. Based on number of wells expected to be drilled as presented in Table V-2 and emissions per day per well drilled as presented in Table A-26 in Appendix A.

2. Based on number of platforms expected to be installed as presented in Table V-3 and emissions per day per platform installed as presented in Table A-27 in Appendix A.

3. Based on the length of pipeline expected to be installed as presented in Table V-4 and emissions per day for subsea pipeline installation as presented in Table A-28 in Appendix A.

4. Based on number of wells expected to be drilled as presented in Table V-2 and emissions per day per well drilled as presented in Table A-29 in Appendix A.

5. Based on emissions presented in Tables A-26, A-27, A-28, A-30 and A-31 in Appendix A.

6. Based on emission factors for diesel fired turbines presented in Table A-1 in Appendix A, power usage factors presented in Table A-3 in Appendix A and production level presented in Table V-1.

7. See Table A-40 in Appendix A for annual emissions associated with overland pipeline installation.

8. Includes workers' vehicles and helicopter. Based on emissions presented in Tables A-26, A-27, A-28, A-30 and A-31 in Appendix A.

Table V-41 (continued)

9. Based on emission factors for diesel fired turbines presented in Table A-1 in Appendix A, 40 percent of power usage for electricity presented in Table A-3 of Appendix A and production level presented in Table V-1.

10. Based on emission factors for natural gas combustion presented in Table A-1 in Appendix A, an average heat requirement of 15,000 Btu/bbl (Energy Resources Co., 1977) and production level presented in Table V-1.

11. Emissions would occur while the tanker or barge is docked at San Francisco. Based upon per visit emissions given in Table A-58 in Appendix A and the expected number of voyages required as presented in Table A-47 in Appendix A.

12. Emissions would occur while the tanker or barge is docked at the OS&T. Based upon per visit emissions given in Table A-58 in Appendix A and the expected number of voyages required as presented in Table A-47 in Appendix A.

13. Emissions would occur while the tanker or barge is en route between the OS&T and the dock in San Francisco. Based upon per visit emissions given in Table A-58 in Appendix A and the expected number of voyages required as presented in Table A-47 in Appendix A.

14. Emissions would occur while the tanker is docked at the OS&T. Based upon per visit emissions given in Table A-61 in Appendix A and the expected number of voyages required as presented in Table A-47 in Appendix A.

15. Emissions would occur while the tanker is traveling in waters between the zone and the southern Monterey County border. Based upon per visit emissions given in Table A-61 in Appendix A and the expected number of voyages required as presented in Table A-47 in Appendix A.

Table V-42. ANNUAL TOTAL SUSPENDED PARTICULATE EMISSIONS ASSOCIATED WITH LEASE SALE NO. 53 OIL AND GAS DEVELOPMENT - SANTA CRUZ ZONE (MEAN RESOURCE ESTIMATE) (tons/year)

	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1995	2000	2005
OFFSHORE OPERATIONS COMMON TO ALL SCENARIOS													
Exploratory/Delineation Drilling[1]	Neg.	Neg.	Neg.	Neg.	Neg.	--	--	--	--	--	--	--	--
Platform Installation[2]	--	--	--	--	27	27	27	27	--	--	--	--	--
Pipeline Installation (73 days)[3]	--	--	--	--	11	--	--	--	--	--	--	--	--
Development Drilling[4]	--	--	--	--	--	0.4	1	2	2	1	--	--	--
Supportive Activity[5]	2	6	7	5	6	8	15	19	15	12	8	8	8
Production Power Generation[6]	--	--	--	--	--	1	8	16	23	27	15	8	4
(Subtotal - Emissions from Common Offshore Operations)	2	6	7	5	44	36	51	64	40	40	23	16	12
A. SCENARIO 1													
Onshore Emissions													
Pipeline Installation[7]	--	--	--	--	4	--	--	--	--	--	--	--	--
Miscellaneous[8]	0.2	0.6	0.7	0.5	1	1	2	3	1	1	0.7	0.7	0.7
Offshore Emissions													
Pipeline Installation[3]	--	--	--	--	8	--	--	--	--	--	--	--	--
Additional Support Activity[5]	--	--	--	--	0.7	--	--	--	--	--	--	--	--
Power Generation (Oil Pumping)[9]	--	--	--	--	--	0.2	1	3	4	5	3	1	0.8
Oil Processing[10]	--	--	--	--	--	Neg.	0.3	0.5	0.8	0.9	0.5	0.3	0.1
Subtotal	0.2	0.6	0.7	0.5	14	1	3	6	6	7	4	2	2
TOTAL (Scenario 1)	2	7	8	5	58	38	54	70	46	47	27	18	14

Table V-42 (continued)

	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1995	2000	2005
B. SCENARIO 1A:													
Onshore Emissions													
Pipeline Installation[7]	--	--	--	--	4	--	--	--	--	--	--	--	--
Miscellaneous[8]	0.2	0.6	0.7	0.5	1	1	2	3	1	1	0.7	0.7	0.7
Oil Processing[10]	--	--	--	--	--	Neg.	0.3	0.5	0.8	0.9	0.5	0.3	0.1
Offshore Emissions													
Pipeline Installation[3]	--	--	--	--	8	--	--	--	--	--	--	--	--
Additional Support Activity[5]	--	--	--	--	0.7	--	--	--	--	--	--	--	--
Power Generation (Oil Pumping)[9]	--	--	--	--	--	0.2	1	3	4	5	3	1	0.8
Subtotal	0.2	0.6	0.7	0.5	14	1	3	6	6	7	4	2	2
TOTAL (Scenario 1A)	2	7	8	5	58	38	54	70	46	47	27	18	14
C. SCENARIO 2:													
Onshore Emissions													
Pipeline Installation[7]	--	--	--	--	0.3	--	--	--	--	--	--	--	--
Miscellaneous[8]	0.2	0.6	0.7	0.5	1	1	2	3	1	1	0.7	0.7	0.7
Tankers In Port[11]	--	--	--	--	--	0.1	0.5	1	1	2	1	0.5	0.3
Offshore Emissions													
Oil Processing[10]	--	--	--	--	--	Neg.	0.3	0.5	0.8	0.9	0.5	0.3	0.1
Tankers at OS&T[12]	--	--	--	--	--	0.1	0.3	0.6	0.9	1	0.6	0.3	0.2
Tankers in Transit[13]	--	--	--	--	--	0.1	0.5	1	1	2	0.9	0.5	0.3
Subtotal	0.2	0.6	0.7	0.5	1	1	4	6	6	6	4	2	2
TOTAL (Scenario 2)	2	7	8	5	45	38	55	70	46	46	27	18	14

Table V-42 (continued)

	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1995	2000	2005
D. SCENARIO 3													
Onshore Emissions													
Pipeline Installation[7]	--	--	--	--	0.3	--	--	--	--	--	--	--	--
Miscellaneous[8]	0.2	0.6	0.7	0.5	1	1	2	3	1	1	0.7	0.7	0.7
Offshore Emissions													
Oil Processing[10]	--	--	--	--	--	Neg.	0.3	0.5	0.8	0.9	0.5	0.3	0.1
Tankers at OS&T[14]	--	--	--	--	--	0.1	0.5	1	1	2	1	0.5	0.3
Tankers In Transit[15]	--	--	--	--	--	0.1	0.5	1	1	2	1	0.5	0.3
Subtotal	0.2	0.6	0.7	0.5	1	1	3	5	4	6	3	2	1
TOTAL (Scenario 3)	2	7	8	5	45	38	54	70	44	46	26	18	13

1. Based on number of wells expected to be drilled as presented in Table V-2 and emissions per day per well drilled as presented in Table A-26 in Appendix A.

2. Based on number of platforms expected to be installed as presented in Table V-3 and emissions per day per platform installed as presented in Table A-27 in Appendix A.

3. Based on the length of pipeline expected to be installed as presented in Table V-4 and emissions per day for subsea pipeline installation as presented in Table A-28 in Appendix A.

4. Based on number of wells expected to be drilled as presented in Table V-2 and emissions per day per well drilled as presented in Table A-29 in Appendix A.

5. Based on emissions presented in Tables A-26, A-27, A-28, A-30 and A-31 in Appendix A.

6. Based on emission factors for diesel fired turbines presented in Table A-1 in Appendix A, power usage factors presented in Table A-3 in Appendix A and production level presented in Table V-1.

7. See Table A-40 in Appendix A for annual emissions associated with overland pipeline installation.

8. Includes workers' vehicles and helicopter. Based on emissions presented in Tables A-26, A-27, A-28, A-30 and A-31 in Appendix A.

Table V-42 (continued)

9. Based on emission factors for diesel fired turbines presented in Table A-1 in Appendix A, 40 percent of power usage for electricity presented in Table A-3 of Appendix A and production level presented in Table V-1.

10. Based on emission factors for natural gas combustion presented in Table A-1 in Appendix A, an average heat requirement of 15,000 Btu/bbl (Energy Resources Co., 1977) and production level presented in Table V-1.

11. Emissions would occur while the tanker or barge is docked at San Francisco. Based on per visit emissions given in Table A-58 in Appendix A and expected number of voyages required as presented in Table A-47 in Appendix A.

12. Emissions would occur while the tanker or barge is docked at the OS&T. Based upon per visit emissions given in Table A-58 in Appendix A and the expected number of voyages required as presented in Table A-47 in Appendix A.

13. Emissions would occur while the tanker or barge is en route between the OS&T and the dock in San Francisco. Based upon per visit emissions given in Table A-58 in Appendix A and the expected number of voyages required as presented in Table A-47 in Appendix A.

14. Emissions would occur while the tanker is docked at the OS&T. Based upon per visit emissions given in Table A-61 in Appendix A and the expected number of voyages required as presented in Table A-47 in Appendix A.

15. Emissions occur while the tanker is traveling in waters between the zone and the southern Monterey County border. Based upon per visit emissions given in Table A-61 in Appendix A and the expected number of voyages required as presented in Table A-47 in Appendix A.

In addition to the gas pipeline proposed, an oil pipeline would be added under Transportation Scenarios 1 and 1A. Emissions associated with pipeline transport of oil to shore represent only a small fraction of the total emissions within the Santa Cruz zone. Emissions related to compressing gas and pumping gas to shore through a pipeline have been included as emissions associated with production power generation.

c) Onshore Emissions

Should Transportation Scenario 1A be adopted, the onshore gas processing plant, to be located about two miles inland, would be a significant emission source. The facility would emit hydrocarbons, hydrogen sulfide and sulfur oxides from processing activities and nitrogen oxides from diesel-fired turbines in the power plant.

San Francisco would be the land base for larger supply boats while smaller crewboats would likely be based in Santa Cruz.

Onshore miscellaneous emission sources would include employees' vehicles and helicopters and are responsible for a relatively small portion of total emissions.

ii. Maximum Hourly Emissions

The expected maximum hourly emissions from oil and gas development in the Santa Cruz zone are tabulated in Tables V-43 and V-44. As was stated in the preceding subsection, the combination of contruction and development activities would result in maximum emissions of nitrogen oxides, carbon monoxide and total suspended particulates during the last year of construction, 1988. Specifically, and in decreasing order, support activities, power generation and platform installation would be the three largest offshore sources of nitrogen oxides, carbon monoxide and total suspended particulates. Miscellaneous onshore activities, which involve predominantly trucks, cars, boats in dock, and helicopters, would also collectively be a prime source of carbon monoxide.

During the peak production year of 1990, the major sources of hydrocarbons would be loading barges or tankers (Transportation Scenarios 2 or 3) and gas processing. Support activities, power generation, and idling tanker or tugboat engines would result in significant emissions of nitrogen oxides, sulfur oxides, carbon monoxide and total suspended particulate as combustion products. Sulfur oxides and hydrogen sulfide would also be emitted by the gas processing plant. If Transportation Scenario 1A were adopted, gas processing emissions would occur onshore. Hourly emissions from gas processing amount to over 300 pounds of hydrocarbons, 15 pounds nitrogen oxides, 16 pounds sulfur oxides and 4 pounds hydrogen sulfide.

iii. Maximum Daily Emissions

The possible activities occurring within a twenty-four hour period have been examined on an hour-by-hour basis to determine what activities could occur in that particular length of time to produce maximum emissions. The results are presented in Tables V-43 and V-44. Footnotes to these tables provide added explanation about the activities resulting in the stated emissions. In general, production, drilling, oil and gas processing and evaporation could occur continuously from a point source for 24 hours. Tankers, support boats and vehicular traffic could move about the zone or even shut down during the same 24 hour interval.

The highest daily emission values for nitrogen oxides, carbon monoxide, and total suspended particulates would be observed in 1988, a year in which both production and construction would occur. The emission sources would be associated with such continuing, recurring events as platform installation, power production, and support activities.

The highest daily emission values for hydrocarbons, sulfur oxides and hydrogen sulfide would occur in 1990. The principal sources of hydrocarbons would be loading tankers or barges and processing gas. Sulfur oxides are combustion products and would result from power generation at the platform and from exhausts of tankers, tugboats and other boats providing support to the platform operations. Hydrogen sulfide would be a result of gas processing.

Daily emissions associated with Scenario 2 includes both loading emissions at OS&T and a portion of unloading emissions at San Francisco terminal. This is a good example of how emissions associated directly with Lease Sale No. 53 may affect areas removed from a particular zone.

iv. Comparison with Regional Air Emission Inventories

Presented in Table V-36 in Section V.D.2.c are projected 1985 emissions from the Bay Area Air Quality Management District (BAAQMD). The 1985 BAAQMD projected emissions are chosen for comparison with estimated emissions from Lease Sale No. 53 OCS activity in the Santa Cruz zone because of the proximity of the zone to the BAAQMD and the fact that 1985 is the year closest to the estimated peak emission years of 1988 and 1990.

Comparisons of the projected 1985 emissions occurring in the BAAQMD and the estimated peak emissions from Lease Sale No. 53 OCS activity in the Santa Cruz zone are presented in Table V-45. As may be seen, the emissions from Lease Sale 53 OCS activity are almost insignificant when compared to the high quantity of emissions expected to occur in 1985 in the BAAQMD. Therefore, for the purpose of putting the Lease Sale No. 53 related emissions in perspective, hydrocarbon emissions from proposed OCS activity in the Santa Cruz zone have also been compared to projected 1987 hydrocarbon emissions for the Monterey Bay Region. These emissions were chosen for comparison purposes because the Santa Cruz zone lies directly to the northwest of Monterey and Santa Cruz Counties and under certain meteorological conditions they may be directed toward this region. No data are available for pollutants other than hydrocarbons.

When analyzing the comparative emission levels, care must be taken in interpreting the results. Substantial quantities of pollutants included in the lease zone totals would occur from mobile sources shuttling between the zone and the San Francisco Bay Area, thereby being dispersed over a large distance. In addition, it must be remembered that the projected regional emissions, as well as the emissions from Lease Sale No. 53 OCS activity, are only estimates of what may occur.

e. Santa Maria

i. Annual Emissions

The annual estimated emissions from Lease Sale No. 53 OCS activity in the Santa Maria zone are presented in Tables V-46 - V-50 based on the pollutant, year, activity and transportation scenario for the mean resource estimate.

Table V-43. MAXIMUM DAILY AND HOURLY EMISSIONS ASSOCIATED WITH LEASE SALE NO. 53 OIL AND GAS DEVELOPMENT - SANTA CRUZ ZONE (PEAK PRODUCTION YEAR - 1990; MEAN RESOURCE ESTIMATE)

Source	Emissions lbs/day (lbs/hr)					
	HC	NO_x	SO_x	CO	TSP	H_2S
OFFSHORE SOURCES COMMON TO ALL SCENARIOS						
Development Drilling[1]	24 (1)	296 (12)	156 (6)	68 (3)	20 (0.8)	--
Support Activity[2]	48 (5)	2,088 (223)	143 (15)	314 (34)	91 (10)	--
Power Generation[3]	146 (6)	1,184 (49)	833 (35)	327 (14)	146 (6)	--
Evaporative Losses[4]	1,657 (69)	--	--	--	--	--
ONSHORE SOURCES COMMON TO ALL SCENARIOS						
Miscellaneous[5]	28 (1)	46 (2)	6 (0.3)	432 (18)	12 (0.5)	--
Subtotal	1,875 (82)	3,614 (286)	1,138 (56)	1,141 (68)	269 (17)	--
SCENARIO 1						
Offshore Sources						
Evaporative Losses (Oil Pipeline)[4]	237 (10)	--	--	--	--	--
Power Generation (Oil Pumping)[6]	27 (1)	257 (11)	135 (6)	54 (2)	27 (1)	--
Oil Processing[7]	4 (0.2)	48 (2)	--	10 (0.4)	5 (0.2)	--
Gas Processing[8]	7,476 (312)	357 (15)	379 (16)	--	--	93 (4)
Subtotal	7,744 (323)	662 (28)	514 (21)	64 (3)	3 (5)	93 (4)
TOTAL (Scenario 1)	9,619 (405)	4,276 (314)	1,652 (77)	1,205 (71)	272 (18)	93 (4)

Table V-43 (continued)

Source	Emissions lbs/day (lbs/hr) HC	NO_x	SO_x	CO	TSP	H_2S
SCENARIO 1A						
Onshore Sources						
Evaporative (Oil Storage Tanks)[9]	19 (0.8)	--	--	--	--	--
Oil Processing[7]	4 (0.2)	48 (2)	--	10 (0.4)	5 (0.2)	--
Gas Processing[8]	7,476 (311)	357 (15)	379 (16)	--	--	93 (4)
Offshore Sources						
Power Generation (Oil Pumping)[6]	27 (1)	257 (11)	135 (6)	54 (2)	27 (1)	--
Evaporative Losses (Oil Pipeline)[4]	237 (10)	--	--	--	--	--
Subtotal	7,763 (324)	662 (28)	514 (21)	64 (3)	32 (1)	93 (4)
TOTAL (Scenario 1A)	9,638 (406)	4,276 (314)	1,652 (77)	1,205 (71)	272 (18)	93 (4)
SCENARIO 2						
Onshore Sources						
Tankers in Port[10]	26	43	3	6	2	--
Offshore Sources						
Oil Processing[7]	4 (0.2)	48 (2)	--	10 (0.4)	5 (0.2)	--
Gas Processing[8]	7,476 (311)	367 (15)	379 (16)	--	--	93 (4)
Tankers @ OS&T[11]	15,669 (1,741)	387 (43)	26 (3)	58 (6)	17 (2)	--
Tankers near Platform[12]	78	129	9	19	6	--
Tankers in Transit[13]	156	258	17	38	11	--
Tankers in Harbor Area[14]	130	215	14	32	10	--
Subtotal	23,513 (2,053)	1,437 (60)	448 (19)	163 (7)	50 (2)	93 (4)
TOTAL (Scenario 2)	25,388 (2,135)	5,051 (346)	1,586 (75)	1,304 (75)	319 (19)	93 (4)

Table V-43 (continued)

Source	Emissions lbs/day (lbs/hr) HC	NO_x	SO_x	CO	TSP	H_2S
SCENARIO 3						
Offshore Sources						
Oil Processing[7]	4 (0.2)	48 (2)	--	10 (0.4)	5 (0.2)	--
Gas Processing[8]	7,476 (311)	357 (15)	379 (16)	--	--	93 (4)
Tankers at OS&T[15]	13,602 (800)	230 (10)	1,508 (65)	3 (0.1)	90 (4)	--
Subtotal	21,082 (1,112)	635 (27)	1,887 (81)	13 (0.5)	95 (4)	93 (4)
TOTAL (Scenario 3)	22,957 (1,194)	4,249 (313)	3,025 (137)	1,154 (68)	364 (21)	93 (4)

1. Based on 4 wells being drilled simultaneously and emissions per day per well drilled presented in Table A-36 in Appendix A.

2. Daily emissions based on Tables A-37 and A-38 presented in Appendix A. Hourly emissions assume 3 crew boats and 3 supply boats operating simultaneously and emission factors presented in Table A-1 in Appendix A.

3. Based on emission factors for diesel fired turbines presented in Table A-1 in Appendix A and production level presented in Table V-1.

4. Based on evaporative emission factors presented in Table A-1 in Appendix A and production level presented in Table V-1.

5. Includes workers' vehicles and helicopter. Based on emissions presented in Tables A-37 and A-38 in Appendix A.

6. Based on emissions factors for diesel fired turbines presented in Table A-1 in Appendix A, 40 percent of the power usage for electricity generation presented in Table A-3 in Appendix A and production level presented in Table V-1.

7. Based on emission factors for natural gas combustion presented in Table A-1 in Appendix A, an average heat requirement of 15,000 Btu/bbl and production level presented in Table V-1.

Table V-43 (continued)

8. Based on emission factors for gas processing presented in Table A-1 of Appendix A and production level presented in Table V-1.

9. Based on equations and values presented in Table A-42 in Appendix A and assumptions discussed in Section V.D.1.

10. Based on 1 hour hoteling in 24 hours.

11. Based on 7 hours of loading and 2 hours of hoteling in 24 hours. Loading produces the maximum hourly emissions.

12. Based on 2 hours of maneuvering about the platform in 24 hours.

13. Based on 6 hours of sea passage in 24 hours.

14. Based on 5 hours of maneuvering in the area landward of the Golden Gate Bridge in 24 hours.

15. Based on 5 hours of discharging ballast, 2 hours of hoteling, and 17 hours of loading. Loading would produce the maximum hourly emissions. Because the selected 24-hour period is spent at at the OS&T, no emissions are given for maneuvering or in transit times.

Table V-44. MAXIMUM DAILY AND HOURLY NITROGEN OXIDES, CARBON MONOXIDE AND TOTAL SUSPENDED PARTICULATE EMISSIONS ASSOCIATED WITH LEASE SALE NO. 53 OCS OIL AND GAS DEVELOPMENT - SANTA CRUZ ZONE

(PEAK EMISSION YEAR - 1988; MEAN RESOURCE ESTIMATE)

Source	Emissions lbs/day (lbs/hr) NO_x	CO	TSP
OFFSHORE SOURCES COMMON TO ALL SCENARIOS			
Platform Installation[1]	4,939 (240)	809 (39)	244 (12)
Development Drilling[2]	296 (12)	68 (3)	20 (0.8)
Power Generation[3]	1,029 (43)	280 (12)	125 (5)
Support Activity[4]	3,331 (372)	501 (56)	145 (16)
ONSHORE SOURCES COMMON TO ALL SCENARIOS			
Miscellaneous[5]	42 (2)	674 (28)	19 (0.8)
Subtotal	9,637 (669)	2,332 (137)	553 (35)
SCENARIO 1			
Offshore Sources			
Power Generation (Oil Pumping)[6]	220 (9)	46 (2)	23 (1)
Oil Processing[7]	41 (2)	8 (0.3)	4 (0.2)
Gas Processing[8]	290 (12)	--	--
Subtotal	551 (23)	54 (2)	27 (1)
TOTAL (Scenario 1)	10,188 (692)	2,386 (139)	580 (36)

Table V-44 (continued)

Source	Emissions lbs/day (lbs/hr) NO_x	CO	TSP
SCENARIO 1A			
Onshore Sources			
Oil Processing[7]	41 (2)	8 (0.3)	4 (0.2)
Gas Processing[8]	290 (12)	--	--
Offshore Sources			
Power Generation (Oil Pumping)[6]	220 (9)	46 (2)	23 (1)
Subtotal	551 (23)	54 (3)	27 (1)
TOTAL (Scenario 1A)	10,188 (692)	2,386 (140)	580 (36)
SCENARIO 2			
Onshore Sources			
Tankers in Port[9]	43	6	2
Offshore Sources			
Oil Processing[7]	41 (2)	8 (0.3)	4 (0.2)
Gas Processing[8]	290 (12)	--	--
Tanker at OS&T[10]	387 (43)	58 (6)	17 (2)
Tanker near Platform[11]	78	19	6
Tanker in Sea Passage[12]	156	38	11
Tanker in Harbor Area[13]	130	32	10
Subtotal	1,125 (57)	161 (7)	50 (2)
TOTAL (Scenario 2)	10,762 (726)	2,493 (144)	603 (37)

Table V-44 (continued)

Source	Emissions lbs/day (lbs/hr) NO_x	CO	TSP
SCENARIO 3			
Offshore Sources			
Oil Processing[7]	41 (2)	8 (0.3)	4 (0.2)
Gas Processing[8]	290 (12)	--	--
Tanker at OS&T[14]	230 (10)	3 (0.1)	90 (4)
Subtotal	561 (24)	11 (0.4)	94 (4)
TOTAL (Scenario 3)	10,198 (693)	2,343 (137)	647 (39)

1. Based on 1 platforms being installed as presented in Table V-3 and emissions per day per platform installed presented in Table A-34 in Appendix A.

2. Based on 4 wells being drilled simultaneously and emissions per day per well drilled presented in Table A-36 in Appendix A.

3. Based on emissions factors for diesel fired turbines presented in Table A-1 in Appendix A and production level presented in Table V-1.

4. Daily emissions based on Tables A-37 and A-38 presented in Appendix A. Hourly emissions assume 5 crew boats and 5 supply boats operating simultaneously and emission factors presented in Table A-1 in Appendix A.

5. Includes workers' vehicles and helicopter. Based on emissions presented in Tables A-37 and A-38 in Appendix A.

6. Based on emission factors for diesel fired turbines presented in Table A-1 in Appendix A, 40 percent of the power usage for electricity generation presented in Table A-3 in Appendix A and production level presented in Table V-1.

7. Based on emission factors for natural gas combustion presented in Table A-1 in Appendix A, an average heat requirement of 15,000 Btu/bbl and production level presented in Table V-1.

8. Based on emission factors for gas processing presented in Table A-1 in Appendix A and production level presented in Table V-1.

Table V-44 (continued)

9. Based on 1 hour hoteling in 24 hours.

10. Based on 7 hours of loading and 2 hours of hoteling in 24 hours. Loading produces the maximum hourly emissions.

11. Based on 2 hours of maneuvering about the platform, 6 hours of sea passage and 5 hours of maneuvering in the area landward of the Golden Gate Bridge in 24 hours.

12. Based on 6 hours of sea passage in 24 hours.

13. Based on 5 hours of maneuvering in the area landward of the Golden Gate Bridge in 24 hours.

14. Based on 5 hours of discharging ballast, 2 hours of hoteling, and 17 hours of loading. Loading produces the maximum hourly emissions. Because the selected 24-hour period is spent at the OS&T, no emissions are given for maneuvering or in transit times.

Table V-45. COMPARISON OF EMISSIONS ASSOCIATED WITH LEASE SALE NO. 53 ACTIVITIES IN THE SANTA CRUZ ZONE WITH COMBINED REGIONAL EMISSION INVENTORY FOR THE BAY AREA AIR QUALITY MANAGEMENT DISTRICT

Pollutant	Peak Emission Year	Tons Per Year[1] (Percentage of Emissions Associated with Lease Sale No. 53 Activities to Regional Emission Inventory)[2,3]			
		Transportation Scenario 1	Transportation Scenario 1A	Transportation Scenario 2	Transportation Scenario 3
Total Hydrocarbons	1990	1,753(0.6%)	1,757(0.6%)	2,490(0.9%)	1,957(0.7%)
[Total Hydrocarbons[4]	1990	1,753 (7%)	1,757(7%)	2,490(10%)[4]	1,957(8%)]
Nitrogen Oxides	1988	1,314(0.5%)	1,314(0.5%)	1,346(0.5%)	1,292(0.5%)
Sulfur Oxides	1990	276(0.2%)	276(0.2%)	258(0.2%)	327(0.2%)
Carbon Monoxide	1988	310(0.02%)	310(0.02%)	313(0.02%)	304(0.02%)
Total Suspended Particulate	1988	71(0.1%)	71(0.1%)	70(0.1%)	70(0.1%)

1. Based on the USGS mean resource estimate.
2. Emissions associated with Lease Sale No. 53 OCS activity in the Santa Cruz zone have been compared to projected 1985 onshore emissions for the Bay Area Air Quality Management District (BAAQMD) Emissions for the BAAQMD have been obtained from the Bay Area Air Quality Plan (Association of Bay Area Governments, 1979).
3. Portions of estimated emissions associated with Lease Sale No. 53 OCS activity in the Santa Cruz zone occur from mobile sources outside of the zone.
4. Based on a comparison with the projected 1987 regional total hydrocarbon emissions for the Monterey Bay region. Emissions from the Monterey Bay region have been obtained from the Air Quality Plan for the Monterey Bay Region (Association of Monterey Bay Area Governments, 1978).

a) Offshore Emissions

Based on the USGS mean resource estimate, exploratory and delineation drilling would begin in 1981 and continue until 1986 (refer to Table V-2 for the actual number of wells drilled per year). Emissions during the exploration phase are not expected to be large in comparison with emissions from other phases. The emissions from exploratory and delineation drilling activities, however, are not insignificant. Emissions of nitrogen oxides (NO_x), for example, are estimated to reach levels as high as 400 tons per year based on the mean resource estimate. A large portion of these emissions would be from support activity. Since most of the supportive emissions would be generated by supply boats, and the supply boats are assumed to originate in the Santa Barbara area, it must be recognized that a large part of the emissions from support boats would occur over the entire distance of supply boat transit.

Development would begin in 1985. Based on the mean resource estimate, there would be 351 development wells drilled and 16 platforms installed by the time development is completed in 1992. As shown in Tables V-46 - V-50, platform installation would be the greatest source of emissions associated with development.

Production would be scheduled to begin in 1986 and peak in 1990, based on the low resource estimate, or 1991, based on the mean and high resource estimates. The types and sources of emissions have been discussed in detail in Section V.B.1.c.

In analyzing Tables V-46 - V-50, it can be seen that there would be one year, 1989, in which emissions of nitrogen oxides, carbon monoxide and total suspended particulates would reach their peak level and another year, 1991, in which hydrocarbons, sulfur oxides, and hydrogen sulfide would reach their maximum level.

To account for these differences in peak emission years, the activities expected to occur in each of the two years must be analyzed. In 1989, there would be two production platforms installed in addition to a relatively high production level. The combination of these activities would account for the high nitrogen oxides, carbon monoxide and particulate emissions estimated for 1989. In 1991, the peak production level would be reached. Emissions from power generation, gas processing and fugitive losses in this year would cause the maximum levels of hydrocarbon, sulfur oxides and hydrogen sulfide emissions to be reached.

b) Transportation Emissions

According to BLM Transportation scenarios for Santa Maria zone crude oil would be transported in one of three ways. The first method would be to pipeline the oil to shore near the Santa Maria River and then transport the oil by overland pipeline until it could be connected to the proposed Santa Barbara County pipeline at Las Flores Canyon. The Santa Barbara County pipeline would connect to refineries in the Los Angeles Basin. The second method would be tankering of crude oil to the refineries in the Los Angeles Basin. The third method would be tankering of the oil to Galveston, Texas.

Gas would be transported from the zone by subsea pipeline to shore near the mouth of the Santa Maria River. There it would connect with an overland pipeline

Table V-46. ANNUAL HYDROCARBON EMISSIONS ASSOCIATED WITH LEASE SALE NO. 53 OCS OIL AND GAS DEVELOPMENT - SANTA MARIA ZONE (MEAN RESOURCE ESTIMATE) (tons/year)

	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1991	1995	2000	2005
OFFSHORE OPERATIONS COMMON TO ALL SCENARIOS														
Exploratory/Delineation Drilling[1]	1	3	4	3	1	0.8	--	--	--	--	--	--	--	--
Platform Installation[2]	--	--	--	--	46	69	46	46	46	--	--	--	--	--
Pipeline installation(76 days)[3]	--	--	--	--	7	--	--	--	--	--	--	--	--	--
Development Drilling[4]	--	--	--	--	--	1	4	5	4	4	3	--	--	--
Supportive Activity[5]	2	5	7	4	10	18	27	28	33	28	23	16	16	16
Production Power Generation[6]	--	--	--	--	--	7	29	54	72	86	91	52	25	12
Evaporative Losses[7]	--	--	--	--	--	75	326	622	825	977	1035	596	286	137
(Subtotal - Emissions from Common Offshore Operations)	3	8	11	7	64	171	432	755	980	1095	1152	664	327	165
A. SCENARIO 1														
Onshore Emissions														
Pipeline installation[8]	--	--	--	--	4	--	--	--	--	--	--	--	--	--
Miscellaneous[9]	0.4	1	2	1	3	7	9	10	10	8	6	4	4	4
Offshore Emissions														
Platform installation[2]	--	--	--	--	--	23	--	--	--	--	--	--	--	--
Pipeline installation (16 days)[3]	--	--	--	--	2	--	--	--	--	--	--	--	--	--
Additional Support Activity[5]	--	--	--	--	0.3	3	--	--	--	--	--	--	--	--
Power Generation (Oil Pumping)[10]	--	--	--	--	--	1	5	10	13	16	17	10	5	2
Evaporative (From Oil Pipeline)[7]	--	--	--	--	--	11	47	89	118	140	148	85	41	20
Gas Processing[11]	--	--	--	--	--	337	1460	2782	3687	4369	4626	2667	1280	613
Oil Processing[12]	--	--	--	--	--	0.2	0.8	1	2	2	2	1	0.7	0.3
Subtotal	0.4	1	2	1	9	382	1522	2892	3830	4535	4799	2767	1331	639
TOTAL (Scenario 1)	3	9	13	8	157	553	1954	3647	4810	5630	5941	3431	1658	804

Table V-46 (continued)

	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1991	1995	2000	2005
B. SCENARIO 1A:														
Onshore Emissions														
Pipeline Installation[8]	--	--	--	--	4	--	--	--	--	--	--	--	--	--
Miscellaneous[9]	0.4	1	2	1	3	6	9	10	10	8	6	4	4	4
Evaporative Losses (From Storage Tanks)[13]	--	--	--	--	--	3	4	6	7	7	7	6	4	4
Gas Processing[11]	--	--	--	--	--	337	1460	2782	3687	4369	4626	2667	1280	613
Oil Processing[12]	--	--	--	--	--	0.2	0.8	1	2	2	2	1	0.7	0.3
Offshore Emissions														
Pipeline Installation (16 days)[3]	--	--	--	--	2	--	--	--	--	--	--	--	--	--
Additional Support Activity[5]	--	--	--	--	0.3	--	--	--	--	--	--	--	--	--
Power Generation (Oil Pumping)[10]	--	--	--	--	--	1	5	10	13	16	17	10	5	2
Evaporative (From Oil Pipeline)[7]	--	--	--	--	--	11	47	89	118	140	148	85	41	20
Subtotal	0.4	1	2	1	9	358	1526	2898	3837	4542	4806	2773	1335	643
TOTAL (Scenario 1A)	3	9	13	8	73	529	1958	3653	4817	5637	5958	3437	1662	808
C. SCENARIO 2:														
Onshore Emissions														
Pipeline Installation[8]	--	--	--	--	0.8	--	--	--	--	--	--	--	--	--
Miscellaneous[9]	0.4	1	2	1	3	7	9	10	10	8	6	4	4	4
Tankers in Port[14]	--	--	--	--	--	6	27	55	67	79	84	48	23	11
Offshore Emissions														
Platform Installation[2]	--	--	--	--	--	23	--	--	--	--	--	--	--	--
Additional Support Activity[5]	--	--	--	--	-	3	--	--	--	--	--	--	--	--
Gas Processing[11]	--	--	--	--	--	337	1460	2782	3687	4369	4626	2667	1280	613
Oil Processing[12]	--	--	--	--	--	0.2	0.8	1	2	2	2	1	0.7	0.3
Tankers at OBT[15]	--	--	--	--	--	61	221	554	680	805	854	490	235	113
Tankers in Transit[16]	--	--	--	--	--	11	50	101	124	147	156	90	43	21
Subtotal	0.4	1	2	1	4	448	1768	3503	4570	5410	5728	3300	1586	762
TOTAL (Scenario 2)	3	9	13	8	68	619	2200	4258	5550	6505	6880	3964	1913	927

Table V-46 (continued)

	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1991	1995	2000	2005
D. SCENARIO 3														
Onshore Emissions														
Pipeline Installation[8]	--	--	--	--	0.8	--	--	--	--	--	--	--	--	--
Miscellaneous[9]	0.4	1	2	1	3	7	9	10	10	8	6	4	4	4
Offshore Emissions														
Platform Installation[2]	--	--	--	--	--	23	--	--	--	--	--	--	--	--
Support Activity[5]	--	--	--	--	--	3	--	--	--	--	--	--	--	--
Gas Processing[11]	--	--	--	--	--	337	1460	2782	3687	4369	4626	2667	1280	613
Oil Processing[12]	--	--	--	--	--	0.2	0.8	1	2	2	2	1	0.7	0.3
Tankers at OS&T[17]	--	--	--	--	--	61	272	517	687	816	864	496	238	116
Tankers in Transit[18]	--	--	--	--	--	0.1	0.4	0.8	1	1	1	0.8	0.4	0.2
Subtotal	0.4	1	2	1	4	431	1742	3311	4387	5196	5499	3169	1523	734
TOTAL (Scenario 3)	3	9	13	8	68	602	2174	4066	5367	6291	6651	3833	1850	898

1. Based on number of wells expected to be drilled as presented in Table V-2 and emissions per day per well drilled as presented in Table A-33 in Appendix A.

2. Based on number of platforms expected to be installed as presented in Table V-3 and emissions per day per platform installed as presented in Table A-34 in Appendix A.

3. Based on the length of pipeline expected to be installed as presented in Table V-4 and emissions per day for subsea pipeline installation as presented in Table A-35 in Appendix A.

4. Based on number of wells expected to be drilled as presented in Table V-2 and emissions per day per well drilled as presented in Table A-36 in Appendix A.

5. Based on emissions presented in Tables A-33, A-34, A-35, A-37 and A-38 in Appendix A.

6. Based on emission factors for diesel fired turbines presented in Table A-1 in Appendix A, power usage factors presented in Table A-3 in Appendix A and production level presented in Table V-1.

7. Based on evaporative emission factors presented in Table A-1 in Appendix A and production level presented in Table V-1.

8. See Table A-40 in Appendix A for annual emissions associated with the installation of onshore pipelines.

Table V-46 (continued)

9. Includes workers' vehicles and helicopter. Based on emissions presented in Tables A-33, A-34, A-35, A-37, and A-38 in Appendix A.

10. Based on emission factors for diesel fired turbines presented in Table A-1 in Appendix A, 40 percent of power usage for electricity presented in Table A-3 Appendix A and production level presented in Table V-1.

11. Based on emission factors for gas processing presented in Table A-1 in Appendix A and production level presented in Table V-1.

12. Based on emission factors for natural gas combustion presented in Table A-1 in Appendix A, an average heat requirement of 15,000 Btu/bbl (Energy Resources Co., 1977) and production level presented in Table V-1.

13. Based on equations and variables presented in Table A-41 in Appendix A and assumptions stated in Section V.D.1.

14. Emissions would occur while the tanker is docked at Los Angeles. Based upon per visit emissions given in Table A-62 in Appendix A and the expected number of voyages required as presented in Table A-47 in Appendix A.

15. Emissions would occur while the tanker is docked at the OS&T. Based upon per visit emissions given in Table A-62 in Appendix A and the expected number of voyages required as presented in Table A-47 in Appendix A.

16. Emissions would occur while the tanker is en route between the OS&T and the dock in Los Angeles. Based upon per visit emissions given in Table A-62 in Appendix A and the expected number of voyages required as presented in Table A-47 in Appendix A.

17. Emissions would occur while the tanker is docked at the OS&T. Based upon per visit emissions given in Table A-64 in Appendix A and the expected number of voyages required as presented in Table A-47 in Appendix A.

18. Emissions would occur while the tanker is traveling between the zone and the southern Santa Barbara County border. Based upon per visit emissions given in Table A-64 in Appendix A and the expected number of voyages required as presented in Table A-47 in Appendix A.

Table V-47. ANNUAL NITROGEN OXIDE EMISSIONS ASSOCIATED WITH LEASE SALE NO. 53 OCS OIL AND GAS DEVELOPMENT - SANTA MARIA ZONE
(MEAN RESOURCE ESTIMATE)
(tons/year)

	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1991	1995	2000	2005
OFFSHORE OPERATIONS COMMON TO ALL SCENARIOS														
Exploratory/Delineation Drilling[1]	30	89	125	81	37	22	--	--	--	--	--	--	--	--
Platform Installation[2]	--	--	--	--	1262	1893	1262	1262	1262	--	--	--	--	--
Pipeline Installation(76 days)[3]	--	--	--	--	199	--	--	--	--	--	--	--	--	--
Development Drilling[4]	--	--	--	--	--	13	46	60	50	47	34	--	--	--
Supportive Activity[5]	71	208	293	189	423	785	1151	1224	1435	1218	1029	708	708	708
Production Power Generation[6]	--	--	--	--	--	54	232	443	587	697	738	425	204	98
(Subtotal - Emissions from Common Offshore Operations)	101	297	418	270	1921	2767	2691	2989	3334	1962	1801	1133	912	806
A. SCENARIO 1														
Onshore Emissions														
Pipeline Installation[7]	--	--	--	--	60	--	--	--	--	--	--	--	--	--
Miscellaneous[8]	0.5	1	2	1	5	8	14	16	16	14	11	6	6	6
Offshore Emissions														
Platform Installation[2]	--	--	--	--	--	631	--	--	--	--	--	--	--	--
Pipeline Installation (16 days)[3]	--	--	--	--	50	--	--	--	--	--	--	--	--	--
Additional Support Activity[5]	--	--	--	--	10	144	--	--	--	--	--	--	--	--
Power Generation (Oil Pumping)[9]	--	--	--	--	--	12	51	97	128	152	160	93	44	21
Oil Processing[10]	--	--	--	--	--	2	10	18	24	29	30	17	8	4
Power Generation[11] (Gas Compression)	--	--	--	--	--	16	70	133	176	208	220	122	61	29
Subtotal	0.5	1	2	1	125	812	145	264	344	403	421	243	119	60
TOTAL (Scenario 1)	102	298	420	271	2046	3579	2836	3253	3678	2365	2222	1376	1031	866

Table V-47 (continued)

	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1991	1995	2000	2005
B. SCENARIO 1A:														
Onshore Emissions														
Pipeline Installation[7]	--	--	--	--	60	--	--	--	--	--	--	--	--	--
Miscellaneous[8]	0.5	1	2	1	5	7	14	16	16	14	11	6	6	6
Oil Processing[10]	--	--	--	--	--	2	10	18	24	29	30	17	8	4
Power Generation (Gas Compression)[11]	--	--	--	--	--	16	70	133	176	208	220	127	61	29
Offshore Emissions														
Pipeline Installation[3]	--	--	--	--	50	--	--	--	--	--	--	--	--	--
Additional Support Activity[9]	--	--	--	--	10	--	--	--	--	--	--	--	--	--
Power Generation (Oil Pumping)[9]	--	--	--	--	--	12	51	97	128	152	160	93	44	21
Subtotal	0.5	1	2	1	125	37	145	264	344	403	421	243	119	60
TOTAL (Scenario 1A)	102	298	420	271	2046	2804	2830	3253	3678	2365	2222	1376	1031	866
C. SCENARIO 2:														
Onshore Emissions														
Pipeline Installation[7]	--	--	--	--	12	--	--	--	--	--	--	--	--	--
Miscellaneous[8]	0.5	1	2	1	5	8	14	16	16	14	11	6	6	6
Tankers In Port[12]	--	--	--	--	--	0.7	3	7	8	10	10	6	3	1
Offshore Emissions														
Platform Installation[2]	--	--	--	--	--	631	--	--	--	--	--	--	--	--
Additional Support Activity[9]	--	--	--	--	--	144	--	--	--	--	--	--	--	--
Oil Processing[10]	--	--	--	--	--	2	10	18	24	29	30	17	8	4
Power Generation (Gas Compression)[11]	--	--	--	--	--	16	70	133	176	208	220	127	61	29
Tankers at OS&T[13]	--	--	--	--	--	0.5	2	4	5	6	7	4	2	0.9
Tankers in Transit[14]	--	--	--	--	--	9	42	85	105	124	131	75	36	17
Subtotal	0.5	1	2	1	17	812	141	263	335	391	409	235	116	58
TOTAL (Scenario 2)	102	298	420	271	1938	3578	2832	3252	3669	2353	2210	1368	1028	864

Table V-47(continued)

	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1991	1995	2000	2005
D. SCENARIO 3														
Onshore Emissions														
Pipeline Installation[7]	--	--	--	--	12	--	--	--	--	--	--	--	--	--
Miscellaneous[8]	0.5	1	2	1	5	8	14	16	16	14	11	6	6	6
Offshore Emissions														
Platform Installation[2]	--	--	--	--	--	631	--	--	--	--	--	--	--	--
Additional Support Activity[5]	--	--	--	--	--	144	--	--	--	--	--	--	--	--
Oil Processing[10]	--	--	--	--	--	2	10	18	24	29	30	17	8	4
Power Generation (Gas Compression)[11]	--	--	--	--	--	16	70	133	176	208	220	127	61	29
Tankers at OS&T[15]	--	--	--	--	--	1	5	9	12	14	15	8	4	2
Tankers In Transit[16]	--	--	--	--	--	1	7	12	17	20	21	12	6	3
Subtotal	0.5	1	2	1	17	803	106	188	245	285	297	170	85	44
TOTAL (Scenario 3)	102	298	420	270	1938	3570	2787	3177	3579	2247	2098	1303	997	850

1. Based on number of wells expected to be drilled as presented in Table V-2 and emissions per day per well drilled as presented in Table A-33 in Appendix A

2. Based on number of platforms expected to be installed as presented in Table V-3 and emissions per day per platform installed as presented in Table A-34 in Appendix A.

3. Based on the length of pipeline expected to be installed as presented in Table V-4 and emissions per day for subsea pipeline installation as presented in Table A-35 in Appendix A.

4. Based on number of wells expected to be drilled as presented in Table V-2 and emissions per day per well drilled as presented in Table A-36 in Appendix A.

5. Based on emissions presented in Tables A-33, A-34, A-35, A-37 and A-38 in Appendix A.

6. Based on emission factors for diesel fired turbines presented in Table A-1 in Appendix A, power usage factors presented in Table A-3 in Appendix A and production level presented in Table V-1.

7. See Table A-40 in Appendix A for annual emissions associated with overland pipeline installation.

8. Includes workers' vehicles and helicopter. Based on emissions presented in Tables A-33, A-34, A-35, A-37 and A-38 in Appendix A.

Table V-47 (continued)

9. Based on emission factors for diesel fired turbines presented in Table A-1 in Appendix A, 40 percent of power usage for electricity presented in Table A-3 of Appendix A and production level presented in Table V-1.

10. Based on emission factors for natural gas combustion presented in Table A-1 in Appendix A, an average heat requirement of 15,000 Btu/bbl (Energy Resources Co., 1977) and production level presented in Table V-1.

11. Based on emission factors for gas processing presented in Table A-1 in Appendix A and production level presented in Table V-1.

12. Emissions would occur while the tanker is docked at Los Angeles. Based upon per visit emissions given in Table A-62 in Appendix A and the expected number of voyages required as presented in Table A-47 in Appendix A.

13. Emissions would occur while the tanker is docked at the OS&T. Based upon per visit emissions given in Table A-62 in Appendix A and the expected number of voyages required as presented in Table A-47 in Appendix A.

14. Emissions would occur while the tanker is en route between the OS&T and the dock in Los Angeles. Based upon per visit emissions given in Table A-62 in Appendix A and the expected number of voyages required as presented in Table A-47 in Appendix A.

15. Emissions would occur while the tanker is docked at the OS&T. Based upon per visit emissions given in Table A-64 in Appendix A and the expected number of voyages required as presented in Table A-47 in Appendix A.

16. Emissions would occur while the tanker is traveling between the zone and the southern Santa Barbara County border. Based upon per visit emissions given in Table A-64 in Appendix A and the expected number of voyages required as presented in Table A-47 in Appendix A.

Table V-48. ANNUAL SULFUR OXIDE EMISSIONS ASSOCIATED WITH LEASE SALE NO. 53 OCS OIL AND GAS DEVELOPMENT - SANTA MARIA ZONE
(MEAN RESOURCE ESTIMATE)
(tons/year)

	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1991	1995	2000	2005
OFFSHORE OPERATIONS COMMON TO ALL SCENARIOS														
Exploratory/Delineation Drilling[1]	2	6	8	5	2	2	--	--	--	--	--	--	--	--
Platform Installation[2]	--	--	--	--	84	126	84	84	84	--	--	--	--	--
Pipeline Installation(76 days)[3]	--	--	--	--	13	--	--	--	--	--	--	--	--	--
Development Drilling[4]	--	--	--	--	--	7	25	32	27	25	18	--	--	--
Supportive Activity[5]	5	14	20	13	29	54	79	84	98	83	70	49	49	49
Production Power Generation[6]	--	--	--	--	--	37	163	311	413	489	518	299	143	69
(Subtotal - Emissions from Common Offshore Operations)	7	20	28	18	128	226	351	511	622	597	606	348	292	118
A. SCENARIO 1														
Onshore Emissions														
Pipeline Installation[7]	--	--	--	--	4	--	--	--	--	--	--	--	--	--
Miscellaneous[8]	0.1	0.3	0.5	0.3	0.6	2	2	2	2	2	2	1	1	1
Offshore Emissions														
Platform Installation[2]	--	--	--	--	--	42	--	--	--	--	--	--	--	--
Pipeline Installation (16 days)[3]	--	--	--	--	3	--	--	--	--	--	--	--	--	--
Additional Support Activity[5]	--	--	--	--	0.7	10	--	--	--	--	--	--	--	--
Power Generation (Oil Pumping)[9]	--	--	--	--	--	6	27	51	67	80	84	49	23	11
Gas Processing[10]	--	--	--	--	--	17	74	140	186	221	233	135	65	31
Subtotal	0.1	0.3	0.5	0.3	8	77	103	193	255	303	319	185	89	43
TOTAL (Scenario 1)	7	20	28	18	136	303	454	704	877	900	925	533	381	161

Table V-48 (continued)

	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1991	1995	2000	2005
B. SCENARIO 1A:														
Onshore Emissions														
Pipeline Installation[7]	--	--	--	--	4	--	--	--	--	--	--	--	--	--
Miscellaneous[8]	0.1	0.3	0.5	0.3	0.6	1	2	2	2	2	2	1	1	1
Gas Processing[10]	--	--	--	--	--	17	74	140	186	221	233	135	65	31
Offshore Emissions														
Pipeline Installation (16 days)[3]	--	--	--	--	3	--	--	--	--	--	--	--	--	--
Additional Support Activity[5]	--	--	--	--	0.7	--	--	--	--	--	--	--	--	--
Power Generation (Oil Pumping)[9]	--	--	--	--	--	6	27	51	67	80	84	49	23	11
Subtotal	0.1	0.3	0.5	0.3	8	24	106	193	255	303	319	185	89	43
TOTAL (Scenario 1A)	7	20	28	18	136	250	454	704	877	900	925	533	381	118
C. SCENARIO 2:														
Onshore Emissions														
Pipeline Installation[7]	--	--	--	--	1	--	--	--	--	--	--	--	--	--
Miscellaneous[8]	0.1	0.3	0.5	0.3	0.6	2	2	2	2	2	2	1	1	1
Tankers In Port[11]	--	--	--	--	--	2	7	13	16	20	21	12	6	3
Offshore Emissions														
Platform Installation[2]	--	--	--	--	--	42	--	--	--	--	--	--	--	--
Additional Support Activity[5]	--	--	--	--	--	10	--	--	--	--	--	--	--	--
Gas Processing[10]	--	--	--	--	--	17	74	140	186	221	233	135	65	31
Tankers at OS&T[12]	--	--	--	--	--	5	20	42	51	61	64	37	18	8
Tankers in Transit[13]	--	--	--	--	--	50	224	459	562	667	707	405	194	94
Subtotal	0.1	0.3	0.5	0.3	2	127	327	656	817	971	1027	590	284	137
TOTAL (Scenario 2)	7	20	28	18	130	353	553	1007	1328	1593	1633	938	576	255

Table V-48 (continued)

	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1991	1995	2000	2005
D. SCENARIO 3														
Onshore Emissions														
Pipeline Installation[7]	--	--	--	--	1	--	--	--	--	--	--	--	--	--
Miscellaneous[8]	0.1	0.3	0.5	0.3	0.6	2	2	2	2	2	2	1	1	1
Offshore Emissions														
Platform Installation[2]	--	--	--	--	--	42	--	--	--	--	--	--	--	--
Additional Support Activity[5]	--	--	--	--	--	10	--	--	--	--	--	--	--	--
Gas Processing[10]	--	--	--	--	--	17	74	140	180	221	233	135	65	31
Tankers at OS&T[14]	--	--	--	--	--	7	30	57	76	90	96	55	26	13
Tankers In Transit[15]	--	--	--	--	--	10	43	82	109	130	137	79	38	18
Subtotal	0.1	0.3	0.5	0.3	2	88	149	281	367	443	468	270	130	63
TOTAL (Scenario 3)	7	20	28	18	130	314	500	792	989	1070	1074	618	422	181

1. Based on number of wells expected to be drilled as presented in Table V-2 and emissions per day per well drilled as presented in Table A-33 in Appendix A.

2. Based on number of platforms expected to be installed as presented in Table V-3 and emissions per day per platform installed as presented in Table A-34 in Appendix A.

3. Based on the length of pipeline expected to be installed as presented in Table V-4 and emissions per day for subsea pipeline installation as presented in Table A-35 in Appendix A.

4. Based on number of wells expected to be drilled as presented in Table V-2 and emissions per day per well drilled as presented in Table A-36 in Appendix A.

5. Based on emissions presented in Tables A-33, A-34, A-35, A-37 and A-38 in Appendix A.

6. Based on emission factors for diesel fired turbines presented in Table A-1 in Appendix A, power usage factors presented in Table A-3 in Appendix A and production level presented in Table V-1.

7. See Table A-40 in Appendix A for annual emissions associated with overland pipeline installation.

8. Includes workers' vehicles and helicopter. Based on emissions presented in Tables A-33, A-34, A-35, A-37 and A-38 in Appendix A.

9. Based on emission factors for diesel fired turbines presented in Table A-1 in Appendix A, 40 percent of power usage for electricity presented in Table A-3 of Appendix A and production level presented in Table V-1.

Table V-48 (continued)

10. Based on emission factors for gas processing presented in Table A-1 in Appendix A and production level presented in Table V-1.

11. Emissions would occur while the tanker is docked at Los Angeles. Based upon per visit emissions given in Table A-62 in Appendix A and the expected number of voyages required as presented in Table A-47 in Appendix A.

12. Emissions would occur while the tanker is docked at the OS&T. Based upon per visit emissions given in Table A-62 in Appendix A and the expected number of voyages required as presented in Table A-47 in Appendix A.

13. Emissions would occur while the tanker is en route between the OS&T and the dock in Los Angeles. Based upon per visit emissions given in Table A-62 in Appendix A and the expected number of voyages required as presented in Table A-47 in Appendix A.

14. Emissions would occur while the tanker is docked at the OS&T. Based upon per visit emissions given in Table A-64 in Appendix A and the expected number of voyages required as presented in Table A-47 in Appendix A.

15. Emissions occur while the tanker is traveling between the zone and the southern Santa Barbara County border. Based upon per visit emissions given in Table A-64 in Appendix A and the expected number of voyages required as presented in Table A-47 in Appendix A.

Table V-49. ANNUAL CARBON MONOXIDE EMISSIONS ASSOCIATED WITH LEASE SALE NO. 53 OCS OIL AND GAS DEVELOPMENT - SANTA MARIA ZONE
(MEAN RESOURCE ESTIMATE)
(tons/year)

	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1991	1995	2000	2005
OFFSHORE OPERATIONS COMMON TO ALL SCENARIOS														
Exploratory/Delineation Drilling[1]	4	13	18	12	3	--	--	--	--	--	--	--	--	--
Platform Installation[2]	--	--	--	--	204	306	204	204	204	--	--	--	--	--
Pipeline Installation(76 days)[3]	--	--	--	--	32	--	--	--	--	--	--	--	--	--
Development Drilling[4]	--	--	--	--	--	3	11	14	12	11	8	--	--	--
Supportive Activity[5]	11	31	44	28	58	98	161	172	192	157	129	77	77	77
Production Power Generation[6]	--	--	--	--	--	15	64	122	162	192	203	117	56	27
(Subtotal - Emissions from Common Offshore Operations)	15	44	62	40	297	422	440	512	570	360	340	194	133	104
A. SCENARIO 1														
Onshore Emissions														
Pipeline Installation[7]	--	--	--	--	14	--	--	--	--	--	--	--	--	--
Miscellaneous[8]	5	14	20	13	52	112	138	154	162	133	101	60	60	60
Offshore Emissions														
Platform Installation[2]	--	--	--	--	--	102	--	--	--	--	--	--	--	--
Pipeline Installation (16 days)[3]	--	--	--	--	8	--	--	--	--	--	--	--	--	--
Additional Support Activity[5]	--	--	--	--	2	22	--	--	--	--	--	--	--	--
Power Generation (Oil Pumping)[9]	--	--	--	--	--	2	11	20	27	32	34	19	9	4
Oil Processing[10]	--	--	--	--	--	0.4	2	4	5	6	6	3	2	0.8
Subtotal	5	14	20	13	76	238	151	178	194	171	141	82	71	65
TOTAL (Scenario 1)	20	58	82	53	373	660	591	690	764	531	481	276	204	169

Table V-49 (continued)

	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1991	1995	2000	2005
B. SCENARIO 1A:														
Onshore Emissions														
Pipeline Installation[7]	--	--	--	--	14	--	--	--	--	--	--	--	--	--
Miscellaneous[8]	5	14	20	13	52	95	138	154	162	133	101	60	60	60
Oil Processing[10]	--	--	--	--	--	0.4	2	4	5	6	6	3	2	0.8
Offshore Emissions														
Pipeline Installation (16 days)[3]	--	--	--	--	8	--	--	--	--	--	--	--	--	--
Additional Support Activity[5]	--	--	--	--	2	--	--	--	--	--	--	--	--	--
Power Generation (Oil Pumping)[9]	--	--	--	--	--	2	11	20	27	32	34	19	9	4
Subtotal	5	14	20	13	76	97	151	178	194	171	141	82	71	65
TOTAL (Scenario 1A)	20	58	82	53	373	519	591	690	764	531	481	276	204	169
C. SCENARIO 2:														
Onshore Emissions														
Pipeline Installation[7]	--	--	--	--	3	--	--	--	--	--	--	--	--	--
Miscellaneous[8]	5	14	20	13	52	110	138	154	162	133	101	60	60	60
Tankers In Port[11]	--	--	--	--	--	0.01	0.05	0.1	0.1	0.1	0.2	0.1	0.04	0.02
Offshore Emissions														
Platform Installation[2]	--	--	--	--	--	102	--	--	--	--	--	--	--	--
Additional Support Activity[5]	--	--	--	--	--	22	--	--	--	--	--	--	--	--
Oil Processing[10]	--	--	--	--	--	0.4	2	4	5	6	6	3	2	0.8
Tankers at OS&T[12]	--	--	--	--	--	0.01	0.04	0.1	0.1	0.1	0.1	0.1	0.03	0.02
Tankers in Transit[13]	--	--	--	--	--	0.3	1	3	4	4	5	3	1	0.6
Subtotal	5	14	20	13	55	235	141	161	171	144	112	66	63	61
TOTAL (Scenario 2)	20	58	82	53	352	657	581	673	741	504	452	260	196	165

Table V-49 (continued)

	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1991	1995	2000	2005
D. SCENARIO 3														
Onshore Emissions														
Pipeline Installation[7]	--	--	--	--	3	--	--	--	--	--	--	--	--	--
Miscellaneous[8]	5	14	20	13	52	110	138	154	162	133	101	60	60	60
Offshore Emissions														
Platform Installation[2]	--	--	--	--	--	102	--	--	--	--	--	--	--	--
Additional Support Activity[9]	--	--	--	--	--	22	--	--	--	--	--	--	--	--
Oil Processing[10]	--	--	--	--	--	0.4	2	4	5	6	6	3	2	0.8
Tankers at OS&T[14]	--	--	--	--	--	0.01	0.1	0.1	0.1	0.2	0.2	0.1	0.04	0.02
Tankers In Transit[15]	--	--	--	--	--	0.02	0.1	0.2	0.2	0.2	0.3	0.1	0.1	0.03
Subtotal	5	14	20	13	55	234	140	158	167	139	108	63	62	61
TOTAL (SCENARIO 3)	20	58	82	53	352	656	580	670	737	499	448	257	195	165

1. Based on number of wells expected to be drilled as presented in Table V-2 and emissions per day per well drilled as presented in Table A-33 in Appendix A.

2. Based on number of platforms expected to be installed as presented in Table V-3 and emissions per day per platform installed as presented in Table A-34 in Appendix A.

3. Based on the length of pipeline expected to be installed as presented in Table V-4 and emissions per day for subsea pipeline installation as presented in Table A-35 in Appendix A.

4. Based on number of wells expected to be drilled as presented in Table V-2 and emissions per day per well drilled as presented in Table A-36 in Appendix A.

5. Based on emissions presented in Tables A-33, A-34, A-35, A-37 and A-38 in Appendix A.

6. Based on emission factors for diesel fired turbines presented in Table A-1 in Appendix A, power usage factors presented in Table A-3 in Appendix A and production level presented in Table V-1.

7. See Table A-40 in Appendix A for annual emissions associated with overland pipeline installation.

8. Includes workers' vehicles and helicopter. Based on emissions presented in Tables A-33, A-34, A-35, A-37 and A-38 in Appendix A.

9. Based on emission factors for diesel fired turbines presented in Table A-1 in Appendix A, 40 percent of power usage for electricity presented in Table A-3 of Appendix A and production level presented in Table V-1.

Table V-49 (continued)

10. Based on emission factors for natural gas combustion presented in Table A-1 in Appendix A, an average heat requirement of 15,000 Btu/bbl (Energy Resources Co., 1977) and production level presented in Table V-1.

11. Emissions would occur while the tanker is docked at Los Angeles. Based upon per visit emissions given in Table A-62 in Appendix A and the expected number of voyages required as presented in Table A-47 in Appendix A.

12. Emissions would occur while the tanker is docked at the OS&T. Based upon per visit emissions given in Table A-62 in Appendix A and the expected number of voyages required as presented in Table A-47 in Appendix A.

13. Emissions would occur while the tanker is en route between the OS&T and the dock in Los Angeles. Based upon per visit emissions given in Table A-62 in Appendix A and the expected number of voyages required as presented in Table A-47 in Appendix A.

14. Emissions would occur while the tanker is docked at the OS&T. Based upon per visit emissions given in Table A-64 in Appendix A and the expected number of voyages required as presented in Table A-47 in Appendix A.

15. Emissions occur while the tanker is traveling between the zone and the southern Santa Barbara County border. Based upon per visit emissions given in Table A-64 in Appendix A and the expected number of voyages required as presented in Table A-47 in Appendix A.

Table V-50. ANNUAL TOTAL SUSPENDED PARTICULATE EMISSIONS ASSOCIATED WITH LEASE SALE NO. 53 OCS OIL AND GAS DEVELOPMENT - SANTA MARIA ZONE (MEAN RESOURCE ESTIMATE) (tons/year)

	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1991	1995	2000	2005
OFFSHORE OPERATIONS COMMON TO ALL SCENARIOS														
Exploratory/Delineation Drilling[1]	Neg.	Neg.	Neg.	Neg.	Neg.	Neg.	--	--	--	--	--	--	--	--
Platform Installation[2]	--	--	--	--	61	92	61	61	61	--	--	--	--	--
Pipeline Installation(76 days)[3]	--	--	--	--	9	--	--	--	--	--	--	--	--	--
Development Drilling[4]	--	--	--	--	--	1	3	4	3	3	2	--	--	--
Supportive Activity[5]	3	9	13	8	18	38	56	59	69	54	45	31	31	31
Production Power Generation[6]	--	--	--	--	--	7	29	54	72	85	91	52	25	12
(Subtotal - Emissions from Common Offshore Operations)	3	9	13	8	88	138	149	178	205	142	138	83	56	43
A. SCENARIO 1														
Onshore Emissions														
Pipeline Installation[7]	--	--	--	--	3	--	--	--	--	--	--	--	--	--
Miscellaneous[8]	0.2	0.5	0.7	0.4	2	3	4	4	4	4	3	1	1	1
Offshore Emissions														
Platform Installation[2]	--	--	--	--	--	31	--	--	--	--	--	--	--	--
Pipeline Installation (16 days)[3]	--	--	--	--	3	--	--	--	--	--	--	--	--	--
Additional Support Activity[5]	--	--	--	--	0.5	6	--	--	--	--	--	--	--	--
Power Generation (Oil Pumping)[9]	--	--	--	--	--	1	5	10	13	16	17	10	5	2
Oil Processing[10]	--	--	--	--	--	0.2	1	2	2	3	3	2	1	0.4
Subtotal	0.2	0.5	0.7	0.4	8	41	10	16	19	23	23	13	7	3
TOTAL (Scenario 1)	3	10	14	8	96	179	159	194	224	165	161	96	63	46

Table V-50 (continued)

	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1991	1995	2000	2005
B. SCENARIO 1A:														
Onshore Emissions														
Pipeline Installation[7]	--	--	--	--	3	--	--	--	--	--	--	--	--	--
Miscellaneous[8]	0.2	0.5	0.7	0.4	2	3	4	4	4	4	3	1	1	1
Oil Processing[10]	--	--	--	--	--	0.2	1	2	2	3	3	2	1	0.4
Offshore Emissions														
Pipeline Installation (16 days)[2]	--	--	--	--	3	--	--	--	--	--	--	--	--	--
Additional Support Activity[5]	--	--	--	--	0.5	--	--	--	--	--	--	--	--	--
Power Generation (Oil Pumping)[9]	--	--	--	--	--	1	5	10	13	16	17	10	5	2
Subtotal	0.2	0.5	0.7	0.4	8	4	10	16	19	23	23	13	7	3
TOTAL (Scenario 1A)	3	10	14	8	96	142	159	194	224	165	161	96	63	46
C. SCENARIO 2:														
Onshore Emissions														
Pipeline Installation[7]	--	--	--	--	0.5	--	--	--	--	--	--	--	--	--
Miscellaneous[8]	0.2	0.5	0.7	0.4	2	3	4	4	4	4	3	1	1	1
Tankers in Port[11]	--	--	--	--	--	0.1	0.6	1	1	2	2	1	0.5	0.2
Offshore Emissions														
Platform Installation[2]	--	--	--	--	--	31	--	--	--	--	--	--	--	--
Additional Support Activity[5]	--	--	--	--	--	6	--	--	--	--	--	--	--	--
Oil Processing[10]	--	--	--	--	--	0.2	1	2	2	3	3	2	1	0.4
Tankers at OS&T[12]	--	--	--	--	--	0.3	1	2	3	4	4	2	1	0.5
Tankers in Transit[13]	--	--	--	--	--	3	14	28	34	41	43	25	12	6
Subtotal	0.2	0.5	0.7	0.4	2	44	15	38	44	53	55	51	16	8
TOTAL (Scenario 2)	3	10	14	8	90	182	164	216	249	195	193	134	72	51

Table V-50 (continued)

	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1991	1995	2000	2005
D. SCENARIO 3														
Onshore Emissions														
Pipeline Installation[7]	--	--	--	--	0.5	--	--	--	--	--	--	--	--	--
Miscellaneous[8]	0.2	0.5	0.7	0.4	2	3	4	4	4	4	3	1	1	1
Offshore Emissions														
Platform Installation[2]	--	--	--	--	--	31	--	--	--	--	--	--	--	--
Additional Support Activity[5]	--	--	--	--	--	6	--	--	--	--	--	--	--	--
Oil Processing[10]	--	--	--	--	--	0.2	1	2	2	3	3	2	1	0.4
Tankers at OS&T[14]	--	--	--	--	--	0.4	2	3	5	5	6	3	2	0.8
Tankers In Transit[15]	--	--	--	--	--	0.6	3	5	7	8	8	5	2	1
Subtotal	0.2	0.5	0.7	0.4	2	41	10	14	18	20	20	11	6	3
TOTAL (Scenario 3)	3	10	14	8	90	179	159	192	223	162	158	94	62	46

1. Based on number of wells expected to be drilled as presented in Table V-2 and emissions per day per well drilled as presented in Table A-33 in Appendix A.

2. Based on number of platforms expected to be installed as presented in Table V-3 and emissions per day per platform installed as presented in Table A-34 in Appendix A.

3. Based on the length of pipeline expected to be installed as presented in Table V-4 and emissions per day for subsea pipeline installation as presented in Table A-35 in Appendix A.

4. Based on number of wells expected to be drilled as presented in Table V-2 and emissions per day per well drilled as presented in Table A-36 in Appendix A.

5. Based on emissions presented in Tables A-33, A-34, A-35, A-37 and A-38 in Appendix A.

6. Based on emission factors for diesel fired turbines presented in Table A-1 in Appendix A, power usage factors presented in Table A-3 in Appendix A and production level presented in Table V-1.

7. See Table A-40 in Appendix A for annual emissions associated with overland pipeline installation.

8. Includes workers' vehicles and helicopter. Based on emissions presented in Tables A-33, A-34, A-35, A-37 and A-38 in Appendix A.

Table V-50 (continued)

9. Based on emission factors for diesel fired turbines presented in Table A-1 in Appendix A, 40 percent of power usage for electricity presented in Table A-3 of Appendix A and production level presented in Table V-1.

10. Based on emission factors for natural gas combustion presented in Table A-1 in Appendix A, an average heat requirement of 15,000 Btu/bbl (Energy Resources Co., 1977) and production level presented in Table V-1.

11. Emissions would occur while the tanker is docked at Los Angeles. Based upon per visit emissions given in Table A-62 in Appendix A and the expected number of voyages required as presented in Table A-47 in Appendix A.

12. Emissions would occur while the tanker is docked at the OS&T. Based upon per visit emissions given in Table A-62 in Appendix A and the expected number of voyages required as presented in Table A-47 in Appendix A.

13. Emissions would occur while the tanker is en route between the OS&T and the dock in Los Angeles. Based upon per visit emissions given in Table A-62 in Appendix A and the expected number of voyages required as presented in Table A-47 in Appendix A.

14. Emissions would occur while the tanker is docked at the OS&T. Based upon per visit emissions given in Table A-64 in Appendix A and the expected number of voyages required as presented in Table A-47 in Appendix A.

15. Emissions occur while the tanker is traveling between the zone and the southern Santa Barbara County border. Based upon per visit emissions given in Table A-64 in Appendix A and the number of voyages required as presented in Table A-47 in Appendix A.

which would transport the gas approximately 14 miles to an existing Southern California Gas (SCG) pipeline.

Emissions associated with oil pumping would be primarily from power generation and evaporative losses from pipeline valves and flanges. These emissions, which would occur only if BLM Transportation Scenario 1 or 1A were adopted, are presented in Tables V-46 - V-50.

Emissions from tankering would occur from tanker loading and unloading, tanker transit and other tanker operations such as hoteling and maneuvering. As can be seen in Tables V-46 - V-50, the major pollutants emitted on an annual basis would be sulfur oxides (SO_x) from tanker transit, and hydrocarbons (HC) from tanker loading.

Emissions associated with the transportation of gas would primarily be pollutants associated with power generation and evaporative losses. Emissions from power generation for gas transportation have been included in the emissions estimates presented for production power generation.

c) Onshore Emissions

Should Transportation Scenario 1A be adopted, the onshore oil and gas processing plant would be a significant source of onshore hydrocarbons, sulfur oxides and hydrogen sulfide from gas processing, and nitrogen oxides from power generation.

It is expected that for Transportation Scenario 2, tankers would unload in the Ports of Los Angeles and Long Beach. Emissions from tanker operations in port are also presented in Tables V-46 - V-50.

Miscellaneous onshore emissions would include pollutants from workers' vehicles, light duty trucks and a supporting helicopter.

ii. Maximum Hourly Emissions

Maximum hourly emissions are included to present the magnitude of emissions that may occur if all operations that could conceivably happen simultaneously in one hour would occur.

Table V-51 presents estimated maximum hourly emissions from Lease Sale No. 53 OCS activity in the Santa Maria zone for the peak production year, based on the mean resource estimate. These emissions are presented with the activities expected to generate them. In addition, Table V-52 gives the estimated maximum hourly emissions of nitrogen oxides (NO_x), carbon monoxide (CO) and total suspended particulte (TSP) for the estimated peak emission year for these pollutants, based on the mean resource estimate.

Emissions associated with production and processing are expected to be emitted at a steady rate. Some emissions, however, would occur only intermittently, e.g., evaporative losses from tanker loading. As shown in Table V-51, tanker loading would be one of the largest single hourly sources of hydrocarbons, although on an annual basis these emissions would not be as significant because loading occurs only intermittently.

iii. Maximum Daily Emissions

Included in Tables V-51 and V-52 are estimated maximum daily emissions. These emissions are included to show an averaging period other than the extremes of the maximum hourly and the total annual.

Emissions from production and processing would be produced at a steady rate. Emissions from support vessels and tankers, however, would occur only for limited periods during a day. The daily emissions from support activities presented in Tables V-51 and V-52 are based on Tables A-34, A-37 and A-38 in Appendix A. Daily emissions associated with tankering operations are based on the per visit emissions presented in Tables A-62 and A-64 in Appendix A.

iv. Comparison with Regional Emission Inventories

San Luis Obispo and Santa Barbara Counties emission inventories, projected for 1990 are presented in Tables V-53 and V-54 respectively. These projections are obtained from the latest Air Quality Plans from each county. As the Santa Maria zone lies off the coast of both counties, the sum of the projected emissions in both counties is used for comparison purposes. Also, 1990 is the year closest to the estimated proposed OCS activity peak emission years of 1989 and 1991, for which emission projections exist.

Table V-55 presents a comparison between the projected regional emissions and the peak annual emissions year estimated for the Santa Maria zone for the mean resource estimate. When comparing the estimated emissions associated with Lease Sale No. 53 OCS activity and the projected onshore emissions from the two counties, caution must be used in interpreting the results. In some cases, high quantities of emissions estimated from Lease Sale No. 53 activity would occur from mobile sources removed from the lease zone. Some of the onshore emissions associated with production in this zone would occur in the Los Angeles area (for example, tanker in-port emissions). Also, the projected regional onshore emissions used for comparison are only estimates of the emission levels that may occur in each county should the trends forecast by each Air Pollution Control District (APCD) be followed.

Finally, it should be noted that the estimated peak emissions from proposed OCS activity in the Santa Maria zone were used for comparison. The expected emissions, and thus the comparative percentages, would be lower in other years of Lease Sale No. 53 activity in the Santa Maria zone.

As may be seen in Table V-55, Lease Sale No. 53 OCS activity in the Santa Maria zone may result in total emissions which could be comparatively significant, particularly for hydrocarbons, nitrogen oxides and sulfur oxides. The major sources of these emissions are discussed in section V.B.1.

It is not expected that significant comparative amounts of carbon monoxide (CO) or total suspended particulates will be generated from Lease Sale No. 53 OCS operations in the Santa Maria zone.

f. Hydrogen Sulfide Emissions

Presented in Table V-56 are the estimated peak annual hydrogen sulfide emissions associated with Lease Sale No. 53 OCS activity in each zone. It is expected that losses from gas processing operations would be the major contributor of hydrogen sulfide. The hydrogen sulfide emissions would occur onshore

Table V-51. MAXIMUM DAILY AND HOURLY EMISSIONS ASSOCIATED WITH LEASE SALE NO. 53 OIL AND GAS DEVELOPMENT - SANTA MARIA ZONE (PEAK PRODUCTION YEAR - 1991; MEAN RESOURCE ESTIMATE)

Source	Emissions lbs/day (lbs/hr)					
	HC	NO_x	SO_x	CO	TSP	H_2S
OFFSHORE SOURCES COMMON TO ALL SCENARIOS						
Development Drilling[1]	36 (2)	438 (18)	234 (10)	102 (4)	30 (1)	--
Support Activity[2]	188 (10)	8,273 (458)	565 (31)	1,125 (66)	365 (20)	--
Power Generation[3]	496 (21)	4,030 (169)	2,835 (118)	1,113 (46)	496 (21)	--
Evaporative Losses[4]	5,915 (246)	--	--	--	--	--
ONSHORE SOURCES COMMON TO ALL SCENARIOS						
Miscellaneous[5]	57 (2)	95 (4)	14 (0.6)	894 (37)	24 (1)	--
Subtotal	6,692 (279)	12,836 (649)	3,649 (160)	3,234 (153)	915 (43)	--
SCENARIO 1						
Offshore Sources						
Evaporative Losses (Oil Pipeline)[4]	845 (35)	--	--	--	--	--
Power Generation (Oil Pumping)[6]	93 (4)	879 (37)	463 (19)	185 (8)	93 (4)	--
Oil Processing[7]	13 (0.5)	165 (7)	1 (0.04)	33 (1)	17 (0.7)	--
Gas Processing[8]	25,347 (1,056)	1,217 (50)	1,279 (53)	--	--	314 (13)
Subtotal	26,298 (1,096)	2,261 (94)	1,743 (73)	218 (9)	110 (5)	314 (13)
TOTAL (Scenario 1)	32,990 (1,375)	15,097 (743)	5,392 (233)	3,452 (162)	1,025 (48)	314 (13)

Table V-51 (continued)

Source	Emissions lbs/day (lbs/hr) HC	NO_x	SO_x	CO	TSP	H_2S
SCENARIO 1A						
Onshore Sources						
Evaporative (Oil Storage Tanks)[9]	41 (2)	--	--	--	--	--
Oil Processing[7]	13 (0.5)	165 (7)	1 (0.04)	33 (1)	17 (0.7)	--
Gas Processing[8]	25,347 (1,056)	1,217 (50)	1,279 (53)	--	--	314 (13)
Offshore Sources						
Power Generation (Oil Pumping)[6]	93 (4)	879 (37)	463 (19)	185 (8)	93 (4)	--
Evaporative Losses (Oil Pipeline)[4]	845 (35)	--	--	--	--	--
Subtotal	26,339 (1,097)	2,261 (94)	1,743 (73)	218 (9)	110 (5)	314 (13)
TOTAL (Scenario 1A)	33,031 (1,376)	15,097 (743)	5,392 (233)	3,452 (162)	1,025 (48)	314 (13)
SCENARIO 2						
Offshore Sources						
Oil Processing[7]	13 (0.5)	165 (7)	1 (0.04)	33 (1)	17 (0.7)	--
Gas Processing[8]	25,347 (1,056)	1,217 (50)	1,279 (53)	--	--	314 (13)
Tankers at OS&T[10]	16,185 (1,598)	128 (16)	1,216 (58)	2 (0.1)	65 (3)	--
Tankers near Platform[11]	306	96	714	1	43	--
Tankers In Sea Passage[12]	416	336	2,120	4	128	--
Subtotal	42,267 (2,654)	1,946 (73)	5,330 (111)	40 (2)	253 (4)	314 (13)
TOTAL (Scenario 2)	48,959 (2,933)	14,782 (722)	8,979 (271)	3,274 (155)	1,168 (47)	314 (13)

Table V-51 (continued)

Source	Emissions lbs/day (lbs/hr) HC	NO_x	SO_x	CO	TSP	H_2S
SCENARIO 3						
Offshore Sources						
Oil Processing[6]	13 (0.5)	165 (7)	1 (0.04)	33 (1)	17 (0.7)	--
Gas Processing[8]	25,347 (1,056)	1,217 (50)	1,279 (53)	--	--	314 (13)
Tankers at OS&T[13]	13,602 (800)	230 (10)	1,508 (65)	3 (0.1)	90 (4)	--
Subtotal	38,962 (1,856)	1,612 (67)	2,788 (118)	36 (2)	107 (5)	314 (13)
TOTAL (Scenario 3)	45,654 (2,135)	14,452 (716)	6,437 (278)	3,270 (155)	1,022 (48)	314 (13)

1. Based on 6 wells being drilled simultaneously and emissions per day per well drilled presented in Table A-36 in Appendix A.

2. Daily emissions based on Tables A-37 and A-38 presented in Appendix A. Hourly emissions assume 5 crew boats and 5 supply boats operating simultaneously and emission factors presented in Table A-1 of Appendix A.

3. Based on emission factors for diesel fired turbines presented in Table A-1 of Appendix A and production level presented in Table V-1.

4. Based on evaporative emission factors presented in Table A-1 in Appendix A and production level presented in Table V-1.

5. Includes workers' vehicles and helicopter. Based on emissions presented in Tables A-37 and A-38 in Appendix A.

6. Based on emission factors for diesel fired turbines presented in Table A-1 in Appendix A, 40 percent of the power usage for electricity generation presented in Table A-3 in Appendix A and production level presented in Table V-1.

7. Based on emission factors for natural gas combustion presented in Table A-1 in Appendix A, an average heat requirement of 15,000 Btu/bbl and production level presented in Table V-1.

8. Based on emission factors for gas processing presented in Table A-1 in Appendix A and production level presented in Table V-1.

Table V-51 (continued)

9. Based on equations and variables presented in Table V-41 in Appendix A and assumptions stated in Section V.D.1.

10. Based on 10 hours of loading, 5 hours of discharging ballast and 2 hours of hoteling by 2 ships operating in parallel from the 2 platforms. Loading would produce maximum hourly emissions.

11. Based on 3 hours of maneuvering about the 2 platforms by 2 ships operating in parallel.

12. Based on 4 hours of sea passage by 2 ships operating in parallel.

13. Based on 5 hours of discharging ballast, 2 hours of hoteling, and 17 hours of loading. Because these activities require an entire 24-hour period, no emissions are given for any maneuvering or transit time by the tanker.

Table V-52. MAXIMUM DAILY AND HOURLY NITROGEN OXIDES, CARBON MONOXIDE AND TOTAL SUSPENDED PARTICULATE EMISSIONS ASSOCIATED WITH LEASE SALE NO. 53 OCS OIL AND GAS DEVELOPMENT - SANTA MARIA ZONE

(PEAK EMISSION YEAR - 1989; MEAN RESOURCE ESTIMATE)

Source	Emissions lbs/day (lbs/hr) NO_x	CO	TSP
OFFSHORE SOURCES COMMON TO ALL SCENARIOS			
Platform Installation[1]	9,878(480)	1,618(78)	488(23)
Development Drilling[2]	730(30)	170(7)	50(2)
Power Generation[3]	3,259(136)	886(37)	395(16)
Support Activity[4]	12,521(527)	1,802(86)	551(25)
ONSHORE SOURCES COMMON TO ALL SCENARIOS			
Miscellaneous[5]	156(6)	1,564(65)	29(1)
Subtotal	26,544(1,180)	6,040(273)	1,725(68)
SCENARIO 1			
Offshore Sources			
Power Generation (Oil Pumping)[6]	701(29)	148(6)	74(3)
Oil Processing[7]	132(6)	26(1)	13(0.5)
Gas Processing[8]	925(38)	--	--
Subtotal	1,758(73)	174(7)	87(4)
TOTAL (Scenario 1)	28,302(1,253)	6,214(280)	1,812(72)

Table V-52 (continued)

Source	Emissions lbs/day (lbs/hr) NO_x	CO	TSP
SCENARIO 1A			
Onshore Sources			
Oil Processing[7]	132(6)	26(1)	3(0.5)
Gas Processing[8]	925(38)	--	--
Offshore Sources			
Power Generation (Oil Pumping)[6]	701(29)	148(6)	74(3)
Subtotal	1,758(73)	174(7)	87(4)
TOTAL (Scenario 1A)	28,302(1,253)	6,214(280)	1,812(72)
SCENARIO 2			
Offshore Sources			
Oil Processing[7]	132(6)	26(1)	13(0.5)
Gas Processing[8]	925(38)	--	--
Tanker at OS&T[9]	128(16)	2(0.2)	72(6)
Tanker near Platform[10]	96	1	42
Tanker in Sea Passage[11]	336	4	128
Subtotal	1,620(60)	34(1)	255(7)
TOTAL (Scenario 2)	28,164(1,240)	6,074(274)	1,980(75)

Table V-52 (continued)

Source	Emissions lbs/day (lbs/hr) NO_x	CO	TSP
SCENARIO 3			
Offshore Sources			
Oil Processing[7]	132(5)	26(1)	13(0.5)
Gas Processing[8]	925(38)	--	--
Tanker at OS&T[12]	230(10)	3(0.1)	90(4)
Subtotal	1,287(54)	29(1)	103(4)
TOTAL (Scenario 3)	27,831(1,234)	6,069(274)	1,828(72)

1. Based on 2 platforms being installed as presented in Table V-3 and emissions per day per platform installed presented in Table A-34 in Appendix A.

2. Based on 10 wells being drilled simultaneously and emissions per day per well drilled presented in Table A-36.

3. Based on emissions factors for diesel fired turbines presented in Table A-1 of Appendix A and production level presented in Table V-1.

4. Daily emissions based on Tables A-37 and A-38 presented in Appendix A. Hourly emissions assume 7 crew boats and 7 supply boats operating simultaneously and emission factors presented in Table A-1 in Appendix A.

5. Includes workers' vehicles and helicopter. Based on emissions presented in Tables A-37 and A-38 in Appendix A.

6. Based on emission factors for diesel fired turbines presented in Table A-1 in Appendix A. 40 percent of the power usage for electricity generation presented in Table A-3 in Appendix A and production level presented in Table V01.

7. Based on emission factors for natural gas combustion presented in Table A-1 in Appendix A, an average heat requirement of 15,000 Btu/bbl and production level presented in Table V-1.

8. Based on emission factors for gas processing presented in Table A-1 in Appendix A and production level presented in Table V-1.

Table V-52 (continued)

9. Based on 10 hours of loading, 5 hours of discharging ballast and 2 hours of hoteling by 2 ships operating in parallel from the 2 platforms. Discharging ballast would produce the maximum hourly emissions of non-reactive pollutants.

10. Based on 3 hours of maneuvering about the 2 platforms by 2 ships operating in parallel.

11. Based on 4 hours of sea passage to 2 ships operating in parallel.

12. Based on 5 hours of discharging ballast, 2 hours of hoteling, and 17 hours of loading. Because these activities require an entire 24-hour period, no emissions are given for any maneuvering or transit time by the tanker.

Table V-53. PROJECTED 1990 EMISSIONS FOR SAN LUIS OBISPO COUNTY SOUTH CENTRAL COAST AIR BASIN

Source	Emissions - tons/year (% of total emissions)[1]				
	HC	NO_x	SO_x[2]	CO	TSP[3]
Stationary	11,607(79%)	18,761(74%)	1,205(91%)	6,351(14%)	NA
Off-road Mobile	1,424(10%)	2,701(11%)	928(7%)	1,544(34%)	NA
On-road Mobile	1,588(11%)	3,814(15%)	266(2%)	23,772(52%)	NA
Total	14,619(100%)	25,276(100%)	13,251(100%)	45,563(100%)	41,975(100%)

1. Source: San Luis Obispo County Area Council of Governments, Air Quality Attainment and Maintenance Plan (1978).
2. SO_x emissions are from San Luis Obispo County 1977 emissions inventory. No other data are available.
3. Only projected total TSP emissions are available.

Table V-54. PROJECTED 1990 EMISSIONS FOR SANTA BARBARA SOUTH COAST, LOMPOC/SANTA YNEZ AND SANTA MARIA AREAS[1]

Source	Emissions - tons/year (% of total emissions)				
	RHC[2]	NO_x	SO_x	CO	TSP
Automotive	2,164(24%)	6,037(59%)	--	31,682(74%)	--
Petroleum[3]	2,372(26%)	1,405(14%)	--	1,365(3%)	--
Solvent Evaporation	1,215(13%)	--	--	--	--
Pesticides/Weed Oil	2,511(28%)	--	--	--	--
Other Stationary[4]	606(7%)	1,394(14%)	--	8,034(19%)	--
Aircraft	139(2%)	1,347(13%)	--	1,613(4%)	--
Total	9,008(100%)	10,183(100%)	1,456(100%)[5]	42,694(100%)	3,369(100%)[5]

1. Source: Santa Barbara County Office of Air Quality Planning, Air Quality Attainment Plan (AQAP) Addendum (May, 1979). Projections are to year 1990.
2. Only reactive hydrocarbon (RHC) data are presented in AQAP.
3. Includes marketing, production and marine terminals.
4. Includes fuel combustion, waste burning, agricultural cleaning and drying, and other stationary sources.
5. SO_x and TSP emissions are presented only as totals in AQAP.

Table V-55. COMPARISON OF EMISSIONS ASSOCIATED WITH LEASE SALE NO. 53 ACTIVITIES IN THE SANTA MARIA ZONE WITH REGIONAL EMISSION INVENTORY FOR THE SANTA BARBARA AND SAN LUIS OBISPO COUNTIES

		Tons Per Year[1] (Percentage of Emissions Associated with Lease Sale No. 53 Activities to Regional Emission Inventory)[2,3]			
Pollutant	Peak Emission Year	Transportation Scenario 1	Transportation Scenario 1-A	Transportation Scenario 2	Transportation Scenario 3
Total Hydrocarbon	1991	5,941(19%)	5,958(19%)	6,880(22%)	6,651(21%)
Nitrogen Oxides	1989	3,678(10%)	3,678(10%)	3,669(10%)	3,579(10%)
Sulfur Oxides	1991	925(6%)	925(6%)	1,633(10%)	1,074(9%)
Carbon Monoxide	1989	764(1%)	764(1%)	741(1%)	737(1%)
Total Suspended Particulate	1989	224(0.5%)	224(0.5%)	249(0.5%)	223(0.5%)

1. Based on the USGS mean resource estimate.
2. Emissions associated with Lease Sale No. 53 OCS activity in the Santa Maria Zone have been compared to combined projected 1990 onshore emissions for the Santa Barbara and San Luis Obispo counties. Emissions for Santa Barbara County have been obtained from the Air Quality Attainment Plan (Santa Barbara County Office of Air Quality Planning, 1979) and emissions for San Luis Obispo County have been obtained from the Air Quality Attainment and Maintenance Plan for San Luis Obispo County (San Luis Obispo County Area Council of Governments, 1978).
3. Portions of estimated emissions associated with Lease Sale No. 53 OCS activity in the Santa Maria Zone occur from mobile sources outside of zone.

Table V-56. ANNUAL EMISSIONS OF HYDROGEN SULFIDE FROM LEASE SALE NO. 53 OCS ACTIVITY - MEAN RESOURCE ESTIMATE[1]

(tons/year)

Zone	Scenario	Source/Activity	1986	1987	1988	1989	1990	1991	1995	2000	2005
Eel River	1,2,3	Offshore Gas Processing	13	24	24	24	24	24	11	4	2
	1A	Onshore Gas Processing Plant	13	24	24	24	24	24	11	4	2
Point Arena	1,2,3	Offshore Gas Processing	5	13	20	22	19	16	8	4	2
	1A	Onshore Gas Processing Plant	5	13	20	22	19	16	8	4	2
Bodega[2]	1,1A,2,3		----------	----------	----------	----------	none	----------	----------	----------	----------
Santa Cruz	1,2,3	Offshore Gas Processing	1	5	10	14	17	16	9	5	3
	1A	Onshore Gas Processing Plant	1	5	10	14	17	16	9	5	3
Santa Maria	1,2,3	Offshore Gas Processing	4	18	34	46	54	57	33	16	8
	1A	Onshore Gas Processing Plant	4	18	34	46	54	57	33	16	8

1. Based on emission factors for gas processing presented in Table A-1 in Appendix A and gas production level presented in Table V-1.

2. Hydrogen sulfide is assumed to be emitted primarily in gas processing. As the Bodega Zone is expected to reinject all gas, the hydrogen sulfide emissions are assumed negligible.

if BLM Transportation Scenario 1-A is adopted, or offshore in all other Transportation Scenarios.

Since the Bodega zone is expected to reinject all gas produced, it is assumed that there would be negligible hydrogen sulfide emissions during Lease Sale No. 53 OCS operations in the zone.

3. Effects of Changes in Resource Estimates

Presented in Tables V-57 - V-67 are estimated annual emissions associated with proposed Lease Sale No. 53 OCS activities based on the high and low USGS resource estimates. The methods and assumptions used in estimating the emissions presented in Tables V-57 - V-67 are the same as those used to determine expected emissions in each zone based on the USGS mean resource estimate.

The types of activities which would generate significant quantities of pollutants would remain the same for all three USGS resource estimates. The level of activity, however, would change depending upon the actual quantities of oil and/or gas recovered. The emissions associated with each Lease Sale No. 53 operation would increase or decrease proportionally to the USGS resource estimate being considered. Therefore, it may be assumed that the emissions presented in Tables V-57 - V-67 would be generated by the various Lease Sale No. 53 OCS activities in approximately the same proportions as in the USGS mean resource estimate.

4. Reactive Hydrocarbons in Relation to Total Hydrocarbons

The pollutant identified as total hydrocarbons is actually a very complex mixture of organic compounds. Most of these chemicals can react with one another or with other materials in the air to form new compounds which could potentially become a more serious air pollution problem. Therefore, it becomes necessary to estimate the reactivity of these many constituents of hydrocarbons. In fact, estimating the degree of reactivity of hydrocarbons is essential whenever photochemical modeling is to be done to project the impact of emissions on air quality.

In order to estimate the reactivity of hydrocarbons emitted by oil and gas development operations in Lease Sale No. 53 the following assumptions were made. Only methane and ethane were considered non-reactive. All other classes of hydrocarbons could enter into photochemical reactions. Recent data (Woodward-Clyde, 1979) on the estimated composition of the hydrocarbon portion of sales gas recovered in the Santa Barbara Channel were used for calculating the reactive portion of gas production related emissions. Based on information provided in the above study, fugitive hydrocarbon contain 50 percent by weight C1 (methane), 15 percent by weight C2 (considered all ethane) and 35 percent by weight C3+ (organic compounds other than methane or ethane). Because of the limitations of the model used to distinguish the variation in the reactivity of the numerous classes of hydrocarbons, a simplifying assumption was made that only the C3+ fraction is considered to be reactive. The hydrocarbons resulting from combustion processes and oil production activities were assumed to be 95 percent reactive.

Both the total hydrocarbon and the reactive hydrocarbon emissions for the peak production year in each zone are presented in Table V-68. The values presented in Table V-68 could represent the relative ratio between reactive

Table V-57. ANNUAL HYDROCARBON EMISSIONS FROM LEASE SALE NO. 53 OCS ACTIVITY[1]
(LOW RESOURCE ESTIMATE)

Zone	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1995	2000	2005
	(tons/year)												
EEL RIVER													
Scenarios 1,1A, 2,3	0.5	1	1	1	3	633	1,164	1,101	866	732	325	158	67
POINT ARENA													
Scenarios 1,2	2	6	4	1	35	550	1,539	1,680	1,657	1,397	608	260	116
Scenario 1A	2	6	4	1	37	550	1,539	1,680	1,657	1,397	608	260	116
Scenario 3	2	6	4	1	35	528	1,481	1,618	1,592	1,347	590	252	112
BODEGA													
Scenario 1,1A, 2	0.6	1	1	--	26	42	70	68	59	58	59	36	23
Scenario 3	0.6	1	1	--	26	24	35	33	31	30	23	17	14
SANTA CRUZ													
Scenario 1	2	6	7	3	49	65	99	149	183	183	121	86	57
Scenario 1A	2	6	7	3	49	66	100	150	184	184	122	87	58
Scenario 2	2	6	7	3	38	77	142	204	262	262	176	123	82
Scenario 3	2	6	7	3	38	71	111	166	204	204	138	98	70
SANTA MARIA													
Scenario 1	2	7	7	4	70	174	518	725	917	1,131	726	442	275
Scenario 1A	2	7	7	4	70	177	521	729	921	1,135	730	445	278
Scenario 2	2	7	7	4	63	197	594	832	1,061	1,310	840	513	319
Scenario 3	2	7	7	4	63	191	572	801	1,021	1,263	815	498	309

1. Based on development scenarios developed by the USGS for the low resource estimate as presented in Tables V-2 through V-4 and production level estimates for the low resource estimate as presented in Table V-1. Emissions may be assumed distributed among the various OCS activities in approximately the same proportions as occur in the mean resource emission estimates.

Table V-58. ANNUAL HYDROCARBON EMISSIONS FROM LEASE SALE NO. 53 OCS ACTIVITY[1]
(HIGH RESOURCE ESTIMATE)

Zone	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1991[2]	1995	2000	2005
	(tons/year)													
EEL RIVER														
Scenarios 1, 2,3	1	4	3	2	28	2,256	2,899	2,874	2,874	2,871	--	2,360	2,360	235
POINT ARENA														
Scenarios 1,2	3	12	8	4	35	754	2,224	4,144	4,298	4,011	--	1,531	606	224
Scenario 1A	3	12	8	4	37	754	2,224	4,144	4,298	4,011	--	1,531	606	224
Scenario 3	3	12	8	4	35	730	2,146	3,988	4,141	3,860	--	1,510	600	221
BODEGA														
Scenario 1,1A, 2	2	4	2	--	27	157	478	567	515	441	--	213	105	82
Scenario 3	2	4	2	--	27	85	261	309	268	232	--	110	57	27
SANTA CRUZ														
Scenario 1	4	11	11	7	81	435	1,513	2,888	3,878	4,179	--	2,119	1,021	493
Scenario 1A	4	11	11	7	81	436	1,515	2,871	3,881	4,183	--	2,122	1,023	495
Scenario 2	4	11	11	7	70	475	1,674	3,201	4,304	4,633	--	2,349	1,133	545
Scenario 3	4	11	11	7	70	479	1,690	3,231	4,341	4,674	--	2,373	1,142	555
SANTA MARIA														
Scenario 1	4	13	15	10	78	736	3,994	6,590	9,440	10,976	11,470	6,854	2,966	1,264
Scenario 1A	4	13	15	10	78	751	3,118	6,596	9,481	11,022	11,518	6,887	2,999	1,281
Scenario 2	4	13	15	10	71	1,268	4,214	8,151	11,209	12,801	13,206	7,938	3,432	1,468
Scenario 3	4	13	15	10	71	807	3,447	7,357	10,555	12,272	12,834	7,673	3,319	1,415

1. Based on development scenarios developed by the USGS for the high resource estimate as presented in Tables V-2 through V-4 and production level estimates for the high resource estimate as presented in Table V-1. Emissions may be assumed distributed among the various OCS activities in approximately the same proportions as occur in the mean resource emission estimates.
2. While emissions occur in all zones in 1991, they have been included only for the Santa Maria zone since this is the peak emission year.

Table V-59. ANNUAL NITROGEN OXIDE EMISSIONS FROM LEASE SALE NO. 53 OCS ACTIVITY[1]
(LOW RESOURCE ESTIMATE)

Zone	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1995	2000	2005
	(tons/year)												
EEL RIVER													
Scenarios 1,1A, 2,3	13	25	38	25	47	148	238	203	179	156	87	59	43
POINT ARENA													
Scenarios 1,2	65	230	166	38	1,035	643	996	822	723	508	370	309	283
Scenario 1A	65	230	166	38	1,081	634	996	822	723	508	370	309	283
Scenario 3	65	230	166	38	1,035	629	643	778	778	473	354	302	281
BODEGA													
Scenario 1,1A,2	19	37	35	--	730	148	171	132	125	124	110	102	96
Scenario 3	19	37	35	--	730	130	138	99	97	96	92	89	87
SANTA CRUZ													
Scenario 1,1A	64	184	202	101	1,243	860	183	877	182	155	121	115	109
Scenario 2	64	184	202	101	999	869	212	915	235	208	159	139	125
Scenario 3	64	184	202	101	999	860	181	875	178	151	119	113	108
SANTA MARIA													
Scenario 1,1A	76	225	223	124	2,001	1,074	1,317	2,085	796	803	507	452	420
Scenario 2	76	225	223	124	1,858	1,074	1,308	2,094	809	817	516	458	423
Scenario 3	76	225	223	124	1,858	1,071	1,309	2,075	783	786	497	445	415

1. Based on development scenarios developed by the USGS for the high resource estimate as presented in Tables V-2 through V-4 and production level estimates for the high resource estimate as presented in Table V-1. Emissions may be assumed distributed among the various OCS activities in approximately the same proportions as occur in the mean resource emission estimates.

Table V-60. ANNUAL NITROGEN OXIDE EMISSIONS FROM LEASE SALE NO. 53 OCS ACTIVITY[1]
(HIGH RESOURCE ESTIMATE)

Zone	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1995	2000	2005
	(tons/year)												
EEL RIVER													
Scenarios 1,1A, 2,3	26	99	74	49	716	433	1,208	539	543	519	519	432	72
POINT ARENA													
Scenarios 1,2	129	416	317	152	1,035	673	2,035	2,009	1,565	1,388	785	629	564
Scenario 1A	129	446	317	152	1,081	673	2,035	2,009	1,565	1,388	785	629	571
Scenario 3	129	446	317	152	1,035	662	2,001	1,944	1,498	1,325	761	620	561
BODEGA													
Scenario 1,1A,2	54	126	70	--	745	206	1,137	436	383	326	198	138	108
Scenario 3	54	126	70	--	745	163	1,009	282	236	200	138	109	95
SANTA CRUZ													
Scenario 1,1A	107	326	340	237	2,168	1,762	2,120	1,876	1,408	1,283	713	491	387
Scenario 2	107	326	340	237	1,924	1,757	2,099	1,835	1,351	1,221	681	474	380
Scenario 3	107	326	340	237	1,924	1,755	2,091	1,818	1,328	1,197	662	468	377
SANTA MARIA													
Scenario 1	127	447	494	345	2,275	3,639	4,554	5,723	4,895	5,326	2,400	1,642	1,310
Scenario 1A	127	447	494	345	2,275	3,639	4,554	4,948	4,895	5,326	2,400	1,642	1,310
Scenario 2	127	447	494	345	1,957	3,697	4,639	5,783	4,915	5,314	2,385	1,635	1,309
Scenario 3	127	447	494	345	1,957	3,629	4,508	5,622	4,748	5,152	2,292	1,595	1,291

1. Based on development scenarios developed by the USGS for the high resource estimate as presented in Tables V-2 through V-4 and production level estimates for the high resource estimate as presented in Table V-1. Emissions may be assumed distributed among the various OCS activities in approximately the same proportions as occur in the mean resource emission estimates.

Table V-61. ANNUAL SULFUR OXIDE EMISSIONS FROM LEASE SALE NO. 53 OCS ACTIVITY[1]
(LOW RESOURCE ESTIMATE)

Zone	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1995	2000	2005
	(tons/year)												
EEL RIVER													
Scenarios 1,1A, 2,3	1	2	4	2	3	74	134	117	97	82	38	19	7
POINT ARENA													
Scenarios 1,2	4	16	11	3	70	188	478	499	487	403	161	89	49
Scenario 1A	4	16	11	3	73	188	478	499	487	403	161	89	49
Scenario 3	4	16	11	3	70	109	255	256	246	198	74	51	32
BODEGA													
Scenario 1,1A	1	3	2	--	49	16	21	16	15	15	12	10	9
Scenario 2	1	3	2	--	49	16	21	16	15	15	12	10	9
Scenario 3	1	3	2	--	49	20	26	21	20	20	18	12	11
SANTA CRUZ													
Scenario 1	4	13	14	7	84	84	28	77	39	34	24	19	15
Scenario 1A	4	13	14	7	84	64	28	77	39	34	24	19	15
Scenario 2	4	13	14	7	68	64	29	78	41	36	25	20	15
Scenario 3	4	13	14	7	68	64	30	79	43	38	26	21	17
SANTA MARIA													
Scenario 1	5	16	15	9	82	96	162	231	179	209	126	86	63
Scenario 1A	5	16	15	9	82	96	162	231	179	209	126	86	63
Scenario 2	5	16	15	9	73	120	243	345	331	399	248	162	110
Scenario 3	5	16	15	9	73	102	183	262	220	262	162	98	76

1. Based on development scenarios developed by the USGS for the high resource estimate as presented in Tables V-2 through V-4 and production level estimates for the high resource estimate as presented in Table V-1. Emissions may be assumed distributed among the various OCS activities in approximately the same proportions as occur in the mean resource emission estimates.

Table V-62. ANNUAL SULFUR OXIDE EMISSIONS FROM LEASE SALE NO. 53 OCS ACTIVITY[1]
(HIGH RESOURCE ESTIMATE)

Zone	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1995	2000	2005
						(tons/year)							
EEL RIVER													
Scenarios 1,1A, 2,3	3	10	7	5	52	252	367	320	320	316	316	261	28
POINT ARENA													
Scenarios 1,2	9	30	22	10	71	196	579	970	961	892	364	160	81
Scenario 1A	9	30	22	10	74	196	579	970	961	892	364	160	81
Scenario 3	9	30	22	10	71	137	404	636	618	568	238	115	64
BODEGA													
Scenario 1,1A	4	9	5	--	50	34	133	94	86	73	38	21	13
Scenario 2	4	9	5	--	50	34	133	94	86	73	38	21	13
Scenario 3	4	9	5	--	50	48	171	140	129	111	56	31	17
SANTA CRUZ													
Scenario 1	7	22	23	16	146	172	348	515	615	637	321	164	90
Scenario 1A	7	22	23	16	146	172	348	515	615	637	321	161	90
Scenario 2	7	22	23	16	130	189	416	646	793	828	417	212	112
Scenario 3	7	22	23	16	130	178	371	560	675	702	354	180	98
SANTA MARIA													
Scenario 1	9	31	34	24	155	333	713	1,254	1,562	1,789	1,041	490	249
Scenario 1A	9	31	34	24	155	333	713	1,202	1,562	1,789	1,041	490	249
Scenario 2	9	31	34	24	144	721	1,539	2,421	2,899	3,174	1,865	845	404
Scenario 3	9	31	34	24	144	361	850	1,557	2,004	2,302	1,364	630	308

1. Based on development scenarios developed by the USGS for the high resource estimate as presented in Tables V-2 through V-4 and production level estimates for the high resource estimate as presented in Table V-1. Emissions may be assumed distributed among the various OCS activities in approximately the same proportions as occur in the mean resource emission estimates.

Table V-63. ANNUAL CARBON MONOXIDE EMISSIONS FROM LEASE SALE NO. 53 OCS ACTIVITY[1]
(LOW RESOURCE ESTIMATE)

Zone	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1995	2000	2005
					(tons/year)								
EEL RIVER													
Scenarios 1,1A, 2,3	3	6	8	5	9	50	75	63	57	51	32	24	20
POINT ARENA													
Scenarios 1,2	11	40	39	9	185	112	190	155	133	93	69	58	53
Scenario 1A	11	40	39	9	193	112	190	155	133	93	69	58	53
Scenario 3	11	40	39	9	185	111	188	153	131	92	68	58	53
BODEGA													
Scenario 1,1A	4	8	7	--	134	40	45	32	31	31	29	27	26
Scenario 2	4	8	7	--	134	40	45	32	31	31	29	27	26
Scenario 3	4	8	7	--	134	38	40	27	27	27	26	25	25
SANTA CRUZ													
Scenario 1,1A	14	40	44	28	244	178	62	184	58	45	34	33	31
Scenario 2	14	40	44	28	193	179	63	185	60	47	35	34	32
Scenario 3	14	40	44	28	193	178	61	183	57	44	33	32	31
SANTA MARIA													
Scenario 1	15	44	44	24	374	212	271	402	176	177	97	86	79
Scenario 1A	15	44	44	24	374	212	271	402	176	177	97	86	79
Scenario 2	15	44	44	24	344	212	268	399	172	174	95	84	77
Scenario 3	15	44	44	24	344	211	268	398	171	172	93	83	77

1. Based on development scenarios developed by the USGS for the high resource estimate as presented in Tables V-1 through V-4 and production level estimates for the high resource estimate as presented in Table V-1. Emissions may be assumed distributed among the various OCS activities in approximately the same proportions as occur in the mean resource emission estimates.

Table V-64. ANNUAL CARBON MONOXIDE EMISSIONS FROM LEASE SALE NO. 53 OCS ACTIVITY[1]
(HIGH RESOURCE ESTIMATE)

Zone	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1995	2000	2005
	(tons/year)												
EEL RIVER													
Scenarios 1,1A, 2,3	6	22	16	11	138	128	280	157	158	148	148	125	28
POINT ARENA													
Scenarios 1,2	23	78	56	27	185	118	376	384	297	263	147	118	106
Scenario 1A	23	78	56	27	193	118	376	384	297	263	147	118	106
Scenario 3	23	78	56	27	185	118	375	382	295	261	146	118	106
BODEGA													
Scenario 1,1A	11	26	15	--	137	151	225	91	79	68	46	34	28
Scenario 2	11	26	15	--	137	151	225	91	79	68	46	34	28
Scenario 3	11	26	15	--	137	144	205	67	55	48	36	29	26
SANTA CRUZ													
Scenario 1,1A	23	71	74	51	420	363	485	488	406	341	175	130	108
Scenario 2	23	71	74	51	368	366	475	473	385	319	164	125	105
Scenario 3	23	71	74	51	368	366	474	472	384	317	163	124	105
SANTA MARIA													
Scenario 1	25	88	97	68	420	692	887	1,149	1,021	1,094	487	327	257
Scenario 1A	25	88	97	68	420	692	887	1,008	1,021	1,094	487	327	257
Scenario 2	25	88	97	68	390	691	875	1,120	976	1,040	454	312	251
Scenario 3	25	88	97	68	390	689	870	1,113	968	1,032	449	310	250

1. Based on development scenarios developed by the USGS for the high resource estimate as presented in Tables V-2 through V-4 and production level estimates for the high resource estimate as presented in Table V-1. Emissions may be assumed distributed among the various OCS activities in approximately the same proportions as occur in the mean resource emission estimates.

Table V-65. ANNUAL TOTAL SUSPENDED PARTICULATE EMISSIONS FROM LEASE SALE NO. 53 OCS ACTIVITY[1]
(LOW RESOURCE ESTIMATE)

(tons/year)

Zone	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1995	2000	2005
EEL RIVER													
Scenarios 1,1A, 2,3	0.3	0.5	1	0.5	2	10	16	14	13	11	6	4	3
POINT ARENA													
Scenarios 1,2	2	9	6	2	38	34	67	60	55	42	25	17	14
Scenario 1A	2	9	6	2	40	34	67	60	55	42	25	17	14
Scenario 3	2	9	6	2	38	29	54	46	41	31	20	16	13
BODEGA													
Scenario 1,1A,2	0.5	1	1	--	35	8	9	7	6	6	6	6	4
Scenario 3	0.5	1	1	--	35	7	8	6	5	5	5	5	4
SANTA CRUZ													
Scenario 1,1A	2	5	5	3	60	42	10	43	11	9	7	7	6
Scenario 2	2	5	5	3	47	42	11	45	13	11	9	7	7
Scenario 3	2	5	5	3	47	42	10	43	11	9	7	6	6
SANTA MARIA													
Scenario 1	2	8	7	4	95	54	68	106	47	49	29	24	21
Scenario 1A	2	8	7	4	95	54	68	106	47	49	29	24	21
Scenario 2	2	8	7	4	89	55	72	112	54	59	35	28	23
Scenario 3	2	8	7	4	89	53	68	105	46	48	28	24	21

1. Based on development scenarios developed by the USGS for the high resource estimate as presented in Tables V-2 through V-4 and production level estimates for the high resource estimate as presented in Table V-1. Emissions may be assumed distributed among the various OCS activities in approximately the same proportions as occur in the mean resource emission estimates.

Table V-66. ANNUAL TOTAL SUSPENDED PARTICULATE EMISSIONS FROM LEASE SALE NO. 53 OCS ACTIVITY[1]
(HIGH RESOURCE ESTIMATE)

	(tons/year)												
Zone	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1995	2000	2005
EEL RIVER													
Scenarios 1,1A, 2,3	0.5	2	1	1	37	30	70	37	38	37	37	31	5
POINT ARENA													
Scenarios 1,2	5	17	12	6	39	35	105	131	112	101	50	34	26
Scenario 1A	5	17	12	6	41	35	105	131	112	101	50	34	26
Scenario 3	5	17	12	6	39	31	95	114	93	122	43	31	25
BODEGA													
Scenario 1,1A,2	2	4	2	--	36	12	60	113	92	21	12	7	6
Scenario 3	2	4	2	--	36	11	57	109	88	18	10	7	5
SANTA CRUZ													
Scenario 1,1A	3	9	9	6	102	87	116	118	105	101	54	33	23
Scenario 2	3	9	9	6	90	87	118	121	108	105	56	34	24
Scenario 3	3	9	9	6	90	87	116	118	103	100	54	33	23
SANTA MARIA													
Scenario 1	4	14	16	11	106	182	252	342	322	356	177	104	72
Scenario 1A	4	14	16	11	106	182	252	299	322	356	177	104	72
Scenario 2	4	14	16	11	100	205	296	401	313	420	214	121	80
Scenario 3	4	14	16	11	100	181	248	334	311	344	169	101	71

1. Based on development scenarios developed by the USGS for the high resource estimate as presented in Tables V-2 through V-4 and production level estimates for the high resource estimate as presented in Table V-1. Emissions may be assumed distributed among the various OCS activities in approximately the same proportions as occur in the mean resource emission estimates.

Table V-67. RANGE OF ANNUAL HYDROGEN SULFIDE EMISSIONS ASSOCIATED WITH LEASE SALE NO. 53 OCS ACTIVITY
LOW RESOURCE ESTIMATE-HIGH RESOURCE ESTIMATE

	(tons/year)[1]								
Zone	1986	1987	1988	1989	1990	1991	1995	2000	2005
Eel River	6-22	12-28	10-28	9-28	7-28	6-28	3-28	2-23	1-2
Point Arena	4-6	12-18	14-34	14-36	11-33	9-28	5-13	2-5	1-2
Bodega[2]	none								
Santa Cruz	0.3-4	1-14	1-27	2-37	2-40	2-37	1-20	1-16	0.5-5
Santa Maria	1-6	5-29	6-62	9-90	11-105	10-110	7-66	4-28	3-12

1. Based on emission factors for gas processing presented in Table A-1 in Appendix A and gas production levels presented in Table V-1.

2. Hydrogen sulfide is assumed to be emitted primarily in gas processing operations. As the Bodega Zone is expected to reinject all gas, the hydrogen sulfide emissions are assumed negligible.

Table V-6a. ANNUAL REACTIVE AND TOTAL HYDROCARBON EMISSIONS ASSOCIATED WITH OCS LEASE SALE NO. 53 OIL AND GAS DEVELOPMENT DURING PEAK PRODUCTION YEAR (MEAN RESOURCE ESTIMATE)[1]

(tons/year)

	Zone and Year									
	Eel River - 1987[2]		Point Arena - 1989		Bodega - 1987[3]		Santa Cruz - 1990		Santa Maria - 1991	
	RHC	(THC)	RHC	(THC)	RHC	(THC)	RHC	(THC)	RHC	(THC)
OFFSHORE OPERATIONS COMMON TO ALL SCENARIOS										
Development Drilling	0.8	(0.8)	1.0	(1)	0.7	(0.7)	1.9	(2)	2.8	(3)
Supportive Activity	1.9	(2)	14	(15)	2.8	(3)	5.7	(6)	22	(23)
Production Power Generation	28	(29)	34	(36)	5.7	(6)	26	(27)	86	(91)
Evaporative Losses	426	(448)	390	(410)	58	(61)	287	(302)	983	(1,035)
Subtotal - Emissions from Common Offshore Operations)	457	(480)	439	(462)	67	(71)	321	(337)	1,094	(1,152)
A. SCENARIO 1										
Onshore Emissions										
Tankers in Port[4]	Not applicable		33	(35)	1.9	(2)	Not applicable		Not applicable	
Miscellaneous	1.9	(2)	1.9	(2)	1.0	(1)	2.8	(3)		
Offshore Emissions									5.7	(6)
Power Generation (Oil Pumping)[5]	Not applicable		Not applicable		Not applicable		4.8	(5)	16	(17)
Evaporative Losses (From Oil Pipeline)[5]	Not applicable		Not applicable		Not applicable		41	(43)	141	(148)
Gas Processing	672	(1,920)	636	(1,817)	Not applicable		477	(1,364)	1,619	(4,626)
Oil Processing	Not applicable		1.0	(1)	0.1	(0.2)	0.7	(0.7)	1.9	(2)
Tankers at OS&T[4]	Not applicable				110	(116)	Not applicable		Not applicable	
Tankers in Transit	Not applicable		58	(61)	3.8	(4)	Not applicable		Not applicable	
Subtotal	674	(1,922)	1,065	(2,259)	117	(123)	521	(1,416)	1,784	(4,789)
TOTAL (Scenario 1)	1,131	(2,402)	1,504	(2,721)	184	(194)	844	(1,753)	2,878	(5,941)

Table V-68 (continued)

	Zone and Year									
	Eel River - 1987[2]		Point Arena - 1989		Bodega - 1987[3]		Santa Cruz - 1990		Santa Maria - 1991	
	RHC	(THC)	RHC	(THC)	RHC	(THC)	RHC	(THC)	RHC	(THC)
B. SCENARIO 1A:										
Onshore Emissions										
Tankers in Port[4]	Not applicable		33	(35)	1.9	(2)	Not applicable		Not applicable	
Miscellaneous	1.9	(2)	1.9	(2)	1.0	(1)	2.8	(3)	5.7	(6)
Evaporative Losses (From Storage Tanks)[6]	Not applicable		Not applicable		Not applicable		3.8	(4)	6.6	(7)
Gas Processing	672	(1,920)	636	(1,817)	Not applicable		477	(1,364)	1,619	(4,626)
Oil Processing[7]	Not applicable		Not applicable		Not applicable		0.7	(0.7)	1.9	(2)
Offshore Emissions										
Oil Processing	Not applicable		1.0	(1)	0.1	(0.2)	Not applicable		Not applicable	
Power Generation (Oil Pumping)[5]	Not applicable		Not applicable		Not applicable		4.8	(5)	16	(17)
Evaporative Losses (From Oil Pumping)[5]	Not applicable		Not applicable		Not applicable		41	(43)	141	(148)
Tankers at OS&T[4]	Not applicable		326	(343)	110	(116)	Not applicable		Not applicable	
Tankers In Transit[4]	Not applicable		58	(61)	3.8	(4)	Not applicable		Not applicable	
Subtotal	674	(1,922)	1,058	(2,259)	117	(123)	530	(1,420)	1,790	(4,806)
TOTAL (Scenario 1A)	1,131	(2,402)	1,497	(2,721)	184	(194	851	(1,757)	2,884	(5,958)
C. SCENARIO 2:										
Onshore Emissions										
Tankers In Port	Not applicable		33	(35)	1.9	(2)	8.5	(8.9)	80	(84)
Miscellaneous	1.9	(2)	1.9	(2)	1.0	(1)	2.8	(3)	5.7	(6)
Offshore Emissions										
Gas Processing	672	(1,920)	636	(1,817)	Not applicable		477	(1,364)	1,619	(4,626)
Oil Processing	Not applicable		1.0	(1)	0.1	(0.2)	0.7	(0.7)	1.9	(2)
Tankers at OS&T	Not applicable		335	(343)	110	(116)	715	(753)	811	(854)
Tankers in Transit	Not applicable		58	(61)	3.8	(4)	22	(23)	148	(156)
Subtotal	674	(1,922)	1,065	(2,259)	117	(123)	1,226	(2,153)	2,666	(5,728)
TOTAL (Scenario 2)	1,131	(2,402)	1,504	(2,721)	184	(194)	1,547	(2,490)	3,760	(6,880)

Table V-68 (continued)

	Zone and Year									
	Eel River - 1987[2]		Point Arena - 1989		Bodega - 1987[3]		Santa Cruz - 1990		Santa Maria - 1991	
	RHC	(THC)	RHC	(THC)	RHC	(THC)	RHC	(THC)	RHC	(THC)
D. SCENARIO 3										
Onshore Emissions										
Miscellaneous	1.9	(2)	1.9	(2)	1.0	(1)	2.8	(3)	5.7	(6)
Offshore Emissions										
Gas Processing	672	(1,920)	636	(1,817)	Not applicable		477	(1,364)	1,619	(4,626)
Oil Processing	Not applicable		1.0	(1)	0.1	(0.2)	0.7	(0.7)	1.9	(2)
Tankers at OS&T	Not applicable		323	(340)	58	(61)	239	(252)	821	(864)
Tankers In Transit	Not applicable		0.3	(0.3)	0.1	(0.1)	0.3	(0.3)	1.0	(1)
Subtotal	674	(1,922)	962	(2,160)	59	(62)	720	(1,620)	2,449	(5,499)
TOTAL (SCENARIO 3)	1,131	(2,402)	1,401	(2,622)	126	(133)	1,041	(1,957)	3,543	(6,651)

1. The quantities of reactive hydrocarbon emissions were calculated from the estimated total hydrocarbon emissions, given in Tables V-12, V-21, V-29, V-38 and V-47 and shown here in parentheses, by using the following assumptions:
   1) gas produced would contain 35 percent reactive hydrocarbons (Standard Oil of California, 1979);
   2) emissions from oil production and transport would contain 95 percent reactive hydrocarbons (AeroVironment, 1978).
2. No oil is expected to be recovered in the Eel River zone.
3. Gas is expected to be reinjected in the Bodega zone.
4. Tankers would not be used to transport oil from Santa Cruz or Santa Maria zones in this scenario.
5. A pipeline would not be used to transport oil from Point Arena or Bodega zones in this scenario.
6. Additional onshore storage tanks would be necessary only at landfalls for the Santa Cruz and Santa Maria zones.
7. Oil processing would be done offshore whenever the oil would be shipped by tanker, but processing would occur onshore whenever the oil would be transported by pipeline.

hydrocarbons and total hydrocarbons for other production years and resource estimates. Gas processing would be the major source of hydrocarbon emissions, accounting for up to 80 percent of total hydrocarbon emissions. However, as stated above, only about 35 percent of this quantity would be reactive. Therefore, general reactivity of total hydrocarbon emissions for all activities in the zones would average about 47 percent.

The photochemical modeling requires an additional level of discrimination of hydrocarbon reactivities. Specific information about assumptions made for modeling purposes are discussed in Section VI.

5. Worst Case Accident

The Bureau of Land Management has assumed that the worst case accident analysis prepared for Lease Sale No. 48 (AeroVironment, 1977) is applicable to Lease Sale No. 53 (Golden, 1979b). Based on the BLM assumption, the worst case accident in the Eel River zone would be a blowout of 1,000,000 cubic feet of natural gas per day, with and without an accompanying fire. The worst case accident in all other zones would be an oil spill of 10,000 barrels. Emission factors and emissions for spills and blowouts are presented in Tables V-69 and V-70.

Section V.B.1.d presents a detailed discussion of the types of accidents that may happen, the probabilities of occurrence, and the emissions associated with each type of accident.

E. Summary

Tables V-71 - V-76 present the maximum annual emission levels expected to result from Lease Sale No. 53 OCS activity in each of the five proposed lease tracts. Emissions are based on the USGS mean resource estimate and are presented for each of the four BLM scenarios. These emissions would be associated with either the high level of construction activity during the development phase, or the peak production year in each zone. Annual emissions would usually decrease drastically after the peak emission year.

Figures V-1 - V-29 provide a more complete picture of annual emissions. These figures present the expected annual emissions associated with Lease Sale No. 53 OCS activity over the study period for each lease zone and pollutant.

It should be noted that the annual emission estimates presented in Tables V-71 - V-76 and Figures V-1 - V-29 include,total emissions related to all Lease Sale No. 53 OCS activity in each zone. Pollutants from some sources may not be emitted in the zone itself, but in ports used for staging support vessels or unloading tankers and barges. Also, signficant quantities of pollutants may be emitted during sea transit of support boats or tankers. Therefore, in assessing the potential impact of the total emissions associated with each zone, careful consideration of the source types (stationary versus mobile) and the source locations in relation to the potential receptor areas is necessary. Tables V-71 - V-76 also give the percentage of total annual emissions from the peak emission and peak production years which would be produced by mobile sources.

Several significant general observations may be made in analyzing Tables V-71 - V-76 and Figures V-1 to V-29:

Table V-69. EMISSION FACTORS AND ASSOCIATED DATA FOR OIL SPILLS AND BLOWOUTS

	Dos Cuadras
Hydrocarbons	
Reid Vapor Pressure	5.5 psi
Volatiles through 500°F	35% by weight
Density	321 lbs/bbl
Volatilization in 1 hour	57 lbs/bbl
Volatilization in 2 hours	86 lbs/bbl
Unburned during a fire	16 lbs/bbl
In gas associated with blowout	44 lbs/10^3 scf[1]
Sulfur Compounds	
H_2S in gas	0.8 lbs/10^3 scf[2]
Total sulfur in gas	0.8 lbs/10^3 scf[2]
SO_2 from gas combustion	1.6 lbs/10^3 scf
Total sulfur in oil	4.2 lbs/bbl
SO_2 from oil combustion	8.4 lbs/bbl
Other pollutants from fires	
NO_x	1.1 lbs/bbl
CO	16 lbs/bbl
Total suspended particulates	3.3 lbs/bbl

1. Assumes 1,000 scf gas are released per barrel of oil.

2. All sulfur assumed to be H_2S for conservatism in analysis.

Source: Aerovironment, Inc. (1977).

Table V-70. EMISSION RATES FROM OIL SPILLS AND BLOWOUTS

(lbs/hr)[1]

Area	140 Barrel Spill		10,000 Barrel Spill		1,000 bbls oil/day 1,000,000 scf gas/day Blowout No Fire		1,000 bbls oil/day 1,000,000 scf gas/day Blowout + Fire				
	1st Hr. THC	2nd Hr. THC	1st Hr. THC	2nd Hr. THC	THC	H_2S	THC	NO_x	CO	SO_2	TSP
Point Arena	8,000	4,100	570,000	290,000	2,000	33	670	46	670	417	140
Bodega	8,000	4,100	570,000	290,000	2,000	33	670	46	670	417	140
Santa Cruz	8,000	4,100	570,000	290,000	2,000	33	670	46	670	417	140
Santa Maria	8,000	4,100	570,000	290,000	2,000	33	670	46	670	417	140
Eel River[2]					1,800	33	1	42	0.8	6	0.5

1. These emission rates are based upon emission factors calculated for Dos Cuadras crude oil by AeroVironment, Inc. in 1977.

2. The Eel River zone is anticipated to yield gas only. It is possible for gas to be lost in a blowout or fire, so estimates of emissions have been made for these two accidents. It was assumed that 1,000,000 scf gas/day would be lost. The emissions from the fire are assumed to best resemble the emissions from natural gas combustion in a residential heating unit. Emission factors in EPA AP-42 (1977) for this combustion process were used.

Table V-71. MAXIMUM HYDROCARBON EMISSIONS ASSOCIATED WITH OCS GAS AND OIL DEVELOPMENT -- MEAN RESOURCE ESTIMATE

Tons/Year - All Sources[1] (Percent of Emissions from Mobile Sources)

Proposed Zone	Peak Emission and Production Year[2]	Transportation Scenario 1 (Tanker-Pipeline Mix)	Transportation Scenario 1-A (Onshore Gas Processing)	Transportation Scenario 2 (100% Tankering)	Transportation Scenario 3 (Tankering to Texas)
Eel River	1987	2,402 (0.2)	2,402 (0.2)	2,402 (0.2)	2,402 (0.2)
Point Arena	1989	2,721 (3)	2,721 (3)	2,721 (3)	2,622 (1)
Bodega	1987	194 (4)	194 (4)	194 (4)	194 (3)
Santa Cruz	1990	1,753 (0.5)	1,757 (0.5)	2,490 (1)	1,957 (0.5)
Santa Maria	1991	5,941 (0.5)	5,958 (0.5)	1,880 (3)	1,651 (0.5)

1. Refer to Section V.D.2 for greater detail on the relative magnitude and location of the various emission sources contributing to the total emissions presented for each transportation scenario.

2. Peak emissions of hydrocarbons are expected to occur during the peak production year.

Table V-72. MAXIMUM NITROGEN OXIDE EMISSIONS ASSOCIATED WITH OCS GAS AND OIL DEVELOPMENT - MEAN RESOURCE ESTIMATE

Tons/Year - All Sources[1] (Percent of Emissions from Mobile Sources)[2]

Proposed Zone	Year	Transportation Scenario 1 (Tanker-Pipeline Mix)	Transportation Scenario 1-A (Onshore Gas Processing)	Transportation Scenario 2 (100% Tankering)	Transportation Scenario 3 (Tankering to Texas)
Eel River					
Peak Emission Year	1985	721 (75)	721 (75)	721 (75)	721 (75)
Peak Production Year	1987	379	379	379	379
Point Arena					
Peak Emission Year	1988	1,322 (72)	1,322 (72)	1,322 (72)	1,281 (71)
Peak Production Year	1989	1,303	1,303	1,303	1,257
Bodega					
Peak Emission Year	1985	730 (62)	730 (62)	730 (62)	730 (62)
Peak Production Year	1987	256	256	256	256
Santa Cruz					
Peak Emission Year	1988	1,314 (69)	1,314 (69)	1,346 (69)	1,292 (70)
Peak Production Year	1990	631	631	686	592
Santa Maria					
Peak Emission Year	1989	3,678 (64)	3,678 (64)	3,669 (67)	3,579 (66)
Peak Production Year	1991	2,222	2,222	2,210	2,098

1. Refer to Section V.D.2 for greater detail on the relative magnitude and location of the various emission sources contributing to the total emissions presented for each transportation scenario.

2. The amount of emissions from mobile sources have only been estimated for the peak emission year.

Table V-73. MAXIMUM SULFUR OXIDE EMISSIONS ASSOCIATED WITH OCS GAS AND OIL DEVELOPMENT -- MEAN RESOURCE ESTIMATE

Tons/Year - All Sources[1] (Percent of Emissions from Mobile Sources)

Proposed Zone	Peak Emission and Production Year[2]	Transportation Scenario 1 (Tanker-Pipeline Mix)	Transportation Scenario 1-A (Onshore Gas Processing)	Transportation Scenario 2 (100% Tankering)	Transportation Scenario 3 (Tankering to Texas)
Eel River	1987	273 (2)	273 (2)	273 (2)	273 (2)
Point Arena	1989	668 (50)	668 (50)	668 (50)	429 (21)
Bodega	1987	50 (22)	50 (22)	50 (22)	66 (33)
Santa Cruz	1990	276 (7)	276 (7)	258 (7)	307 (15)
Santa Maria	1991	925 (8)	925 (8)	1,633 (48)	1,074 (19)

1. Refer to Section V.D.2 for greater detail on the relative magnitude and location of the various emission sources contributing to the total emissions presented for each transportation scenario.

2. Peak emissions of sulfur oxides are expected to occur during the peak production year.

Table V-74. MAXIMUM CARBON MONOXIDE EMISSIONS ASSOCIATED WITH OCS GAS AND OIL DEVELOPMENT - MEAN RESOURCE ESTIMATE

Tons/Year - All Sources[1] (Percent of Emissions from Mobile Sources)[2]

Proposed Zone	Year	Transportation Scenario 1 (Tanker-Pipeline Mix)	Transportation Scenario 1-A (Onshore Gas Processing)	Transportation Scenario 2 (100% Tankering)	Transportation Scenario 3 (Tankering to Texas)
Eel River					
Peak Emission Year	1987	144 (51)	144 (51)	144 (51)	144 (51)
Peak Production Year	1987	144	144	144	144
Point Arena					
Peak Emission Year	1988	254 (69)	254 (69)	254 (69)	254 (69)
Peak Production Year		248	248	248	248
Bodega					
Peak Emission Year	1985	135 (75)	135 (75)	135 (75)	135 (75)
Peak Production Year	1987	65	65	65	60
Santa Cruz					
Peak Emission Year	1988	310 (73)	310 (73)	313 (73)	304 (75)
Peak Production Year	1990	174	174	179	164
Santa Maria					
Peak Emission Year	1989	764 (64)	764 (64)	741 (67)	737 (66)
Peak Production Year	1991	481	481	452	448

1. Refer to Section V.D.2 for greater detail on the relative magnitude and location of the various emission sources contributing to the total emissions presented for each transportation scenario.

2. The amount of emissions from mobile sources have only been estimated for the peak emission year.

Table V-75. MAXIMUM TOTAL SUSPENDED PARTICULATE EMISSIONS ASSOCIATED WITH OCS GAS AND OIL DEVELOPMENT - MEAN RESOURCE ESTIMATE

Tons/Year - All Sources[1] (Percent of Emissions from Mobile Sources)[2]

Proposed Zone	Year	Transportation Scenario 1 (Tanker-Pipeline Mix)	Transportation Scenario 1-A (Onshore Gas Processing)	Transportation Scenario 2 (100% Tankering)	Transportation Scenario 3 (Tankering to Texas)
Eel River					
Peak Emission Year	1985	36 (63)	36 (63)	36 (63)	36 (63)
Peak Production Year	1987	35	35	35	35
Point Arena					
Peak Emission Year	1989	94 (57)	94 (57)	94 (57)	80 (50
Peak Production Year	1989	94	94	94	80
Bodega					
Peak Emission Year	1985	36 (65)	36 (65)	36 (65)	36 (65)
Peak Production Year	1987	16	16	16	16
Santa Cruz					
Peak Emission Year	1988	70 (54)	70 (54)	70 (56)	70 (56)
Peak Production Year	1990	47	47	47	40
Santa Maria					
Peak Emission Year	1989	224 (50)	224 (50)	249 (59)	223 (54)
Peak Production Year	1991	161	161	193	158

1. Refer to Section V.D.2 for greater detail on the relative magnitude and location of the various emission sources contributing to the total emissions presented for each transportation scenario.

2. The amount of emissions from mobile sources have only been estimated for the peak emission year.

Table V-76. MAXIMUM HYDROGEN SULFIDE EMISSIONS ASSOCIATED WITH OCS GAS AND OIL DEVELOPMENT -- MEAN RESOURCE ESTIMATE

Tons/Year - All Sources[1] (Percent of Emissions from Mobile Sources)[2]

Proposed Zone	Peak Emission and Production Year[3]	Transportation Scenario 1 (Tanker-Pipeline Mix)	Transportation Scenario 1-A (Onshore Gas Processing)	Transportation Scenario 2 (100% Tankering)	Transportation Scenario 3 (Tankering to Texas)
Eel River	1987	24	24	24	24
Point Arena	1989	22	22	22	22
Bodega[4]	None	Neg.	Neg.	Neg.	Neg.
Santa Cruz	1990	17	17	17	17
Santa Maria	1991	57	57	57	57

1. Refer to Section V.D. for greater detail on the relative magnitude and location of the various emission sources contributing to the total emissions presented for each transportation scenario.

2. Virtually all of the hydrogen sulfide would be produced by stationary sources.

3. Peak emissions of hydrogen sulfide are expected to occur during the peak production year.

4. Due to predicted low gas resource estimates, no gas processing plant is anticipated for this zone. Therefore, the hydrogen sulfide emissions are assumed to be negligible.

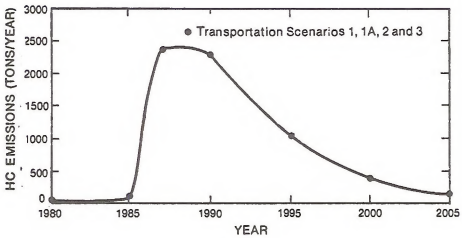

Figure V-1. ANNUAL TOTAL HYDROCARBON (THC) EMISSIONS ASSOCIATED WITH OCS LEASE SALE NO. 53 OIL AND GAS DEVELOPMENT IN THE EEL RIVER ZONE (MEAN RESOURCE ESTIMATE)

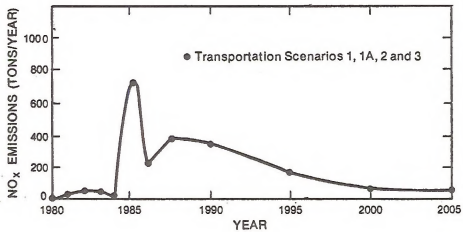

Figure V-2. ANNUAL NITROGEN OXIDE (NO_x) EMISSIONS ASSOCIATED WITH OCS LEASE SALE NO. 53 OIL AND GAS DEVELOPMENT IN THE EEL RIVER ZONE (MEAN RESOURCE ESTIMATE)

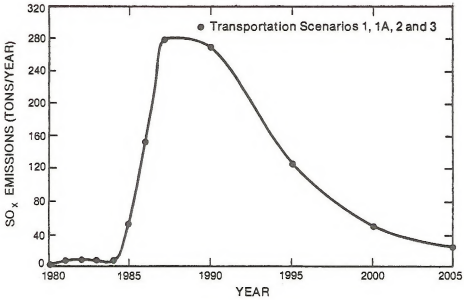

Figure V-3. ANNUAL SULFUR OXIDE (SO_X) EMISSIONS ASSOCIATED WITH OCS LEASE SALE NO. 53 OIL AND GAS DEVELOPMENT IN THE EEL RIVER ZONE (MEAN RESOURCE ESTIMATE)

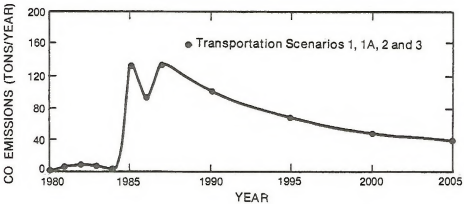

Figure V-4. ANNUAL CARBON MONOXIDE (CO) EMISSIONS ASSOCIATED WITH OCS LEASE SALE NO. 53 OIL AND GAS DEVELOPMENT IN THE EEL RIVER ZONE (MEAN RESOURCE ESTIMATE)

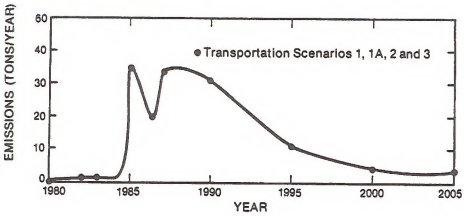

Figure V-5. ANNUAL TOTAL SUSPENDED PARTICULATE (TSP) EMISSIONS ASSOCIATED WITH OCS LEASE SALE NO. 53 OIL AND GAS DEVELOPMENT IN THE EEL RIVER ZONE (MEAN RESOURCE ESTIMATE)

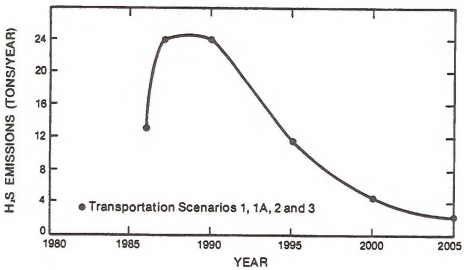

Figure V-6. ANNUAL HYDROGEN SULFIDE (H_2S) EMISSIONS ASSOCIATED WITH OCS LEASE SALE NO. 53 OIL AND GAS DEVELOPMENT IN THE EEL RIVER ZONE (MEAN RESOURCE ESTIMATE)

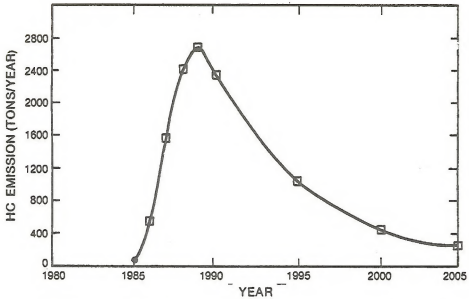

Figure V-7. ANNUAL TOTAL HYDROCARBON (THC) EMISSIONS ASSOCIATED WITH OCS LEASE SALE NO. 53 OIL AND GAS DEVELOPMENT IN THE POINT ARENA ZONE (MEAN RESOURCE ESTIMATE)

□ Transportation Scenarios 1, 1A, 2 and 3 (Differences in Emissions among Scenarios are Graphically Indistinguishable)

● Points Common to All Scenarios

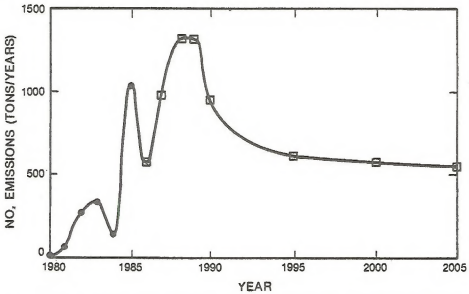

Figure V-8. ANNUAL NITROGEN OXIDE (NO_x) EMISSIONS ASSOCIATED WITH OCS LEASE SALE NO. 53 OIL AND GAS DEVELOPMENT IN THE POINT ARENA ZONE (MEAN RESOURCE ESTIMATE)

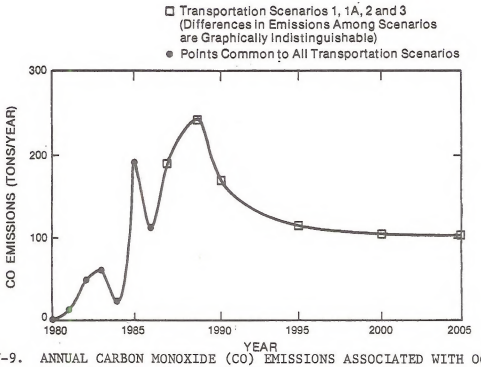

Figure V-9. ANNUAL CARBON MONOXIDE (CO) EMISSIONS ASSOCIATED WITH OCS LEASE SALE NO. 53 OIL AND GAS DEVELOPMENT IN THE POINT ARENA ZONE (MEAN RESOURCE ESTIMATE)

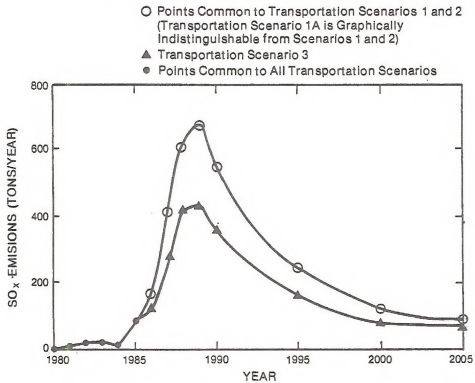

Figure V-10. ANNUAL SULFUR OXIDE (SO_x) EMISSIONS ASSOCIATED WITH OCS LEASE SALE NO. 53 OIL AND GAS DEVELOPMENT IN THE POINT ARENA ZONE (MEAN RESOURCE ESTIMATE)

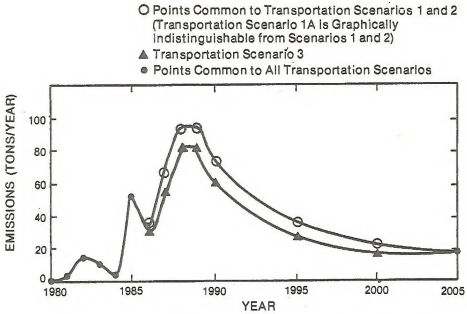

Figure V-11. ANNUAL TOTAL SUSPENDED PARTICULATE (TSP) EMISSIONS ASSOCIATED WITH OCS LEASE SALE NO. 53 OIL AND GAS DEVELOPMENT IN THE POINT ARENA ZONE (MEAN RESOURCE ESTIMATE)

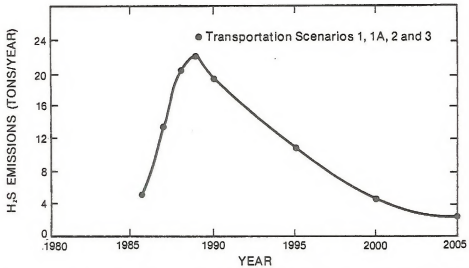

Figure V-12. ANNUAL HYDROGEN SULFIDE (H_2S) EMISSIONS ASSOCIATED WITH OCS LEASE SALE NO. 53 OIL AND GAS DEVELOPMENT IN THE POINT ARENA ZONE (MEAN RESOURCE ESTIMATE)

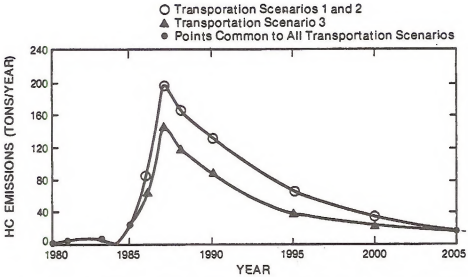

Figure V-13. ANNUAL TOTAL (THC) EMISSIONS ASSOCIATED WITH OCS LEASE SALE NO. 53 OIL AND GAS DEVELOPMENT IN THE BODEGA ZONE (MEAN RESOURCE ESTIMATE)

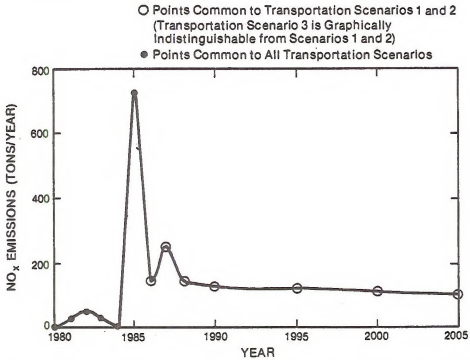

Figure V-14. ANNUAL NITROGEN OXIDE (NO_X) EMISSIONS ASSOCIATED WITH OCS LEASE SALE NO. 53 OIL AND GAS DEVELOPMENT IN THE BODEGA ZONE (MEAN RESOURCE ESTIMATE)

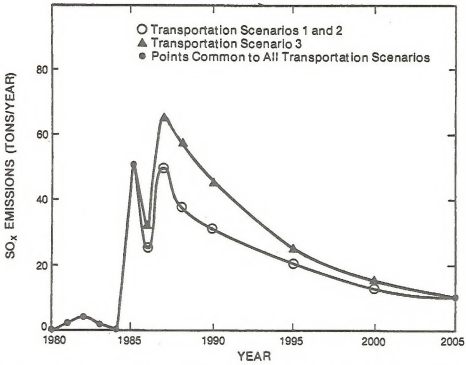

Figure V-15. ANNUAL SULFUR OXIDE (SO_x) EMISSIONS ASSOCIATED WITH OCS LEASE SALE NO. 53 OIL AND GAS DEVELOPMENT IN THE BODEGA ZONE (MEAN RESOURCE ESTIMATE)

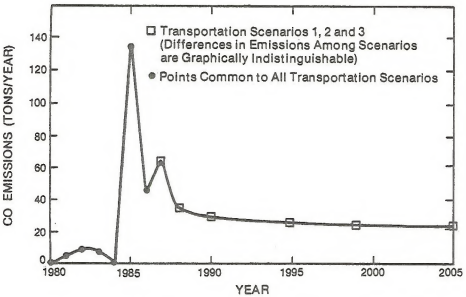

Figure V-16. ANNUAL CARBON MONOXIDE (CO) EMISSIONS ASSOCIATED WITH OCS LEASE SALE NO. 53 OIL AND GAS DEVELOPMENT IN THE BODEGA ZONE (MEAN RESOURCE ESTIMATE)

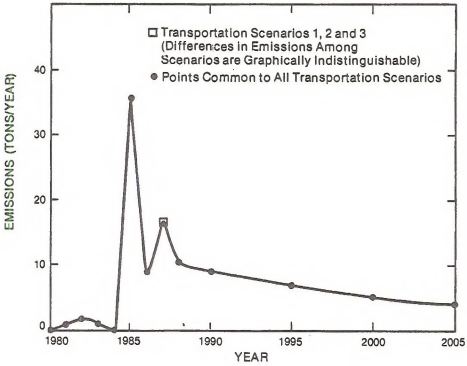

Figure V-17. ANNUAL TOTAL SUSPENDED PARTICULATE (TSP) EMISSIONS ASSOCIATED WITH OCS LEASE SALE NO. 53 OIL AND GAS DEVELOPMENT IN THE BODEGA ZONE (MEAN RESOURCE ESTIMATE)

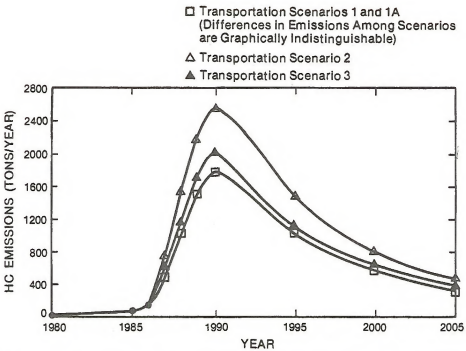

Figure V-18. ANNUAL TOTAL HYDROCARBON (THC) EMISSIONS ASSOCIATED WITH OCS LEASE SALE NO. 53 OIL AND GAS DEVELOPMENT IN THE SANTA CRUZ ZONE (MEAN RESOURCE ESTIMATE)

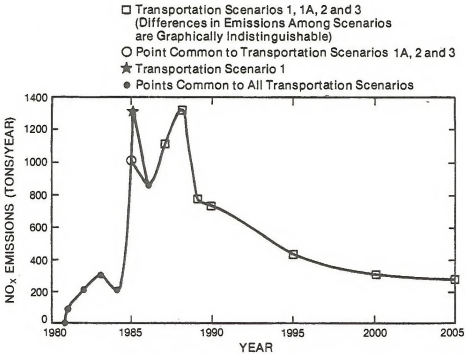

Figure V-19. ANNUAL NITROGEN OXIDE (NO_x) EMISSIONS ASSOCIATED WITH OCS LEASE SALE NO. 53 OIL AND GAS DEVELOPMENT IN THE SANTA CRUZ ZONE (MEAN RESOURCE ESTIMATE)

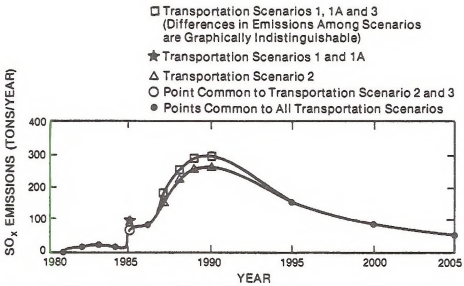

Figure V-20. ANNUAL SULFUR OXIDE (SO_x) EMISSIONS ASSOCIATED WITH OCS LEASE SALE NO. 53 OIL AND GAS DEVELOPMENT IN THE SANTA CRUZ ZONE (MEAN RESOURCE ESTIMATE)

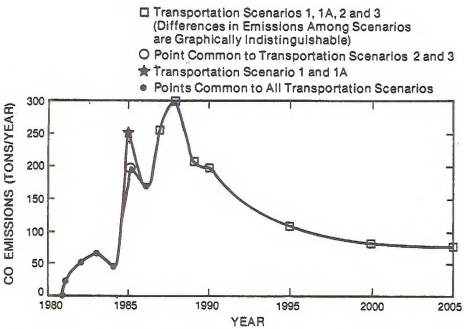

Figure V-21. ANNUAL CARBON MONOXIDE (CO) EMISSIONS ASSOCIATED WITH OCS LEASE SALE NO. 53 OIL AND GAS DEVELOPMENT IN THE SANTA CRUZ ZONE (MEAN RESOURCE ESTIMATE)

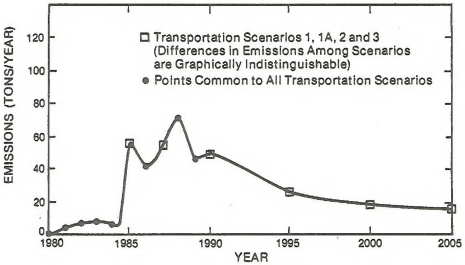

Figure V-22. ANNUAL TOTAL SUSPENDED PARTICULATE (TSP) EMISSIONS ASSOCIATED WITH OCS LEASE SALE NO. 53 OIL AND GAS DEVELOPMENT IN THE SANTA CRUZ ZONE (MEAN RESOURCE ESTIMATE)

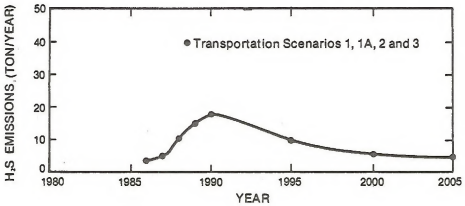

Figure V-23. ANNUAL HYDROGEN SULFIDE (H_2S) EMISSIONS ASSOCIATED WITH OCS LEASE SALE NO. 53 OIL AND GAS DEVELOPMENT IN THE SANTA CRUZ ZONE (MEAN RESOURCE ESTIMATE)

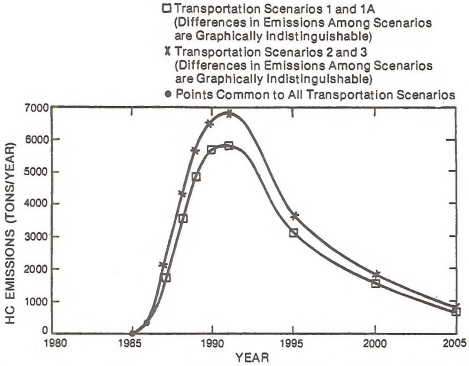

Figure V-24. ANNUAL TOTAL HYDROCARBON (THC) EMISSIONS ASSOCIATED WITH OCS LEASE SALE NO. 53 OIL AND GAS DEVELOPMENT IN THE SANTA MARIA ZONE (MEAN RESOURCE ESTIMATE)

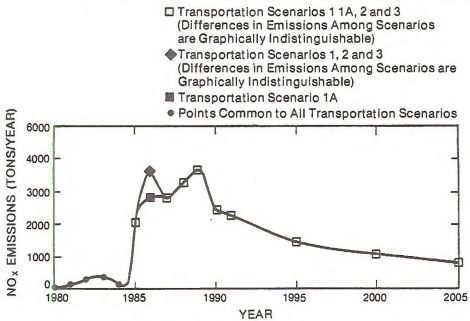

Figure V-25. ANNUAL NITROGEN OXIDES (NO_X) EMISSIONS ASSOCIATED WITH OCS LEASE SALE NO. 53 OIL AND GAS DEVELOPMENT IN THE SANTA MARIA ZONE (MEAN RESOURCE ESTIMATE)

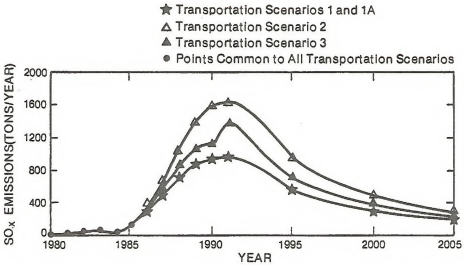

Figure V-26. ANNUAL SULFUR OXIDE (SO_X) EMISSIONS ASSOCIATED WITH OCS LEASE SALE NO. 53 OIL AND GAS DEVELOPMENT IN THE SANTA MARIA ZONE (MEAN RESOURCE ESTIMATE)

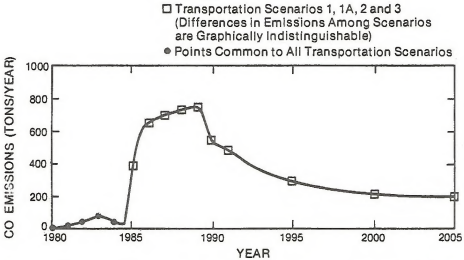

Figure V-27. ANNUAL CARBON MONOXIDE (CO) EMISSIONS ASSOCIATED WITH OCS LEASE SALE NO. 53 OIL AND GAS DEVELOPMENT IN THE SANTA MARIA ZONE (MEAN RESOURCE ESTIMATE)

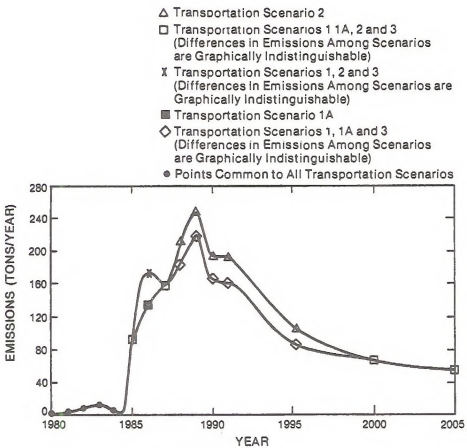

Figure V-28. ANNUAL TOTAL SUSPENDED PARTICULATE (TSP) EMISSIONS ASSOCIATED WITH OCS LEASE SALE NO. 53 OIL AND GAS DEVELOPMENT IN THE SANTA MARIA ZONE (MEAN RESOURCE ESTIMATE)

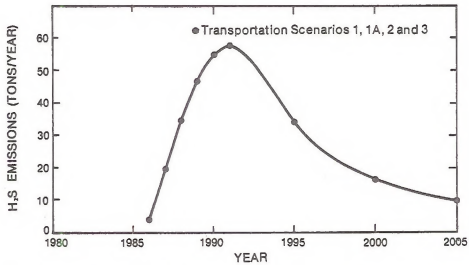

Figure V-29. ANNUAL HYDROGEN SULFIDE (H_2S) EMISSIONS ASSOCIATED WITH OCS LEASE SALE NO. 53 OIL AND GAS DEVELOPMENT IN THE SANTA MARIA ZONE (MEAN RESOURCE ESTIMATE)

1) Emissions of nitrogen oxides, carbon monoxide, and total suspended particulate matter would reach their maximum levels before the peak emission levels of hydrocarbons, sulfur oxides and hydrogen sulfide. Large quantities of nitrogen oxide, carbon monoxide and total suspended particulate matter would be emitted by construction and drilling equipment during development of each lease tract while maximum levels of hydrocarbons, sulfur oxide, and hydrogen sulfide emissions would occur during production.

2) A large portion of the nitrogen oxides, carbon monoxide, and total suspended particulates from oil and gas development in each zone would result from mobile emission sources. Pollutants from mobile sources would be dispersed over a wider area than would emissions of the same magnitude which result from stationary sources.

3) Peak emission levels in each zone would be temporary and occur over a short period of time. [The events which would cause the high emission levels (large scale development, peak production) would themselves take place for only a limited period of time.] Emissions occurring during other years would be substantially lower than the peak annual emissions.

4) Production phase emissions associated with the tanker transport scenarios (BLM Transportation Scenarios 2 and 3) would be higher than emissions which would occur from a pipeline transportation scenario (BLM Transportation Scenarios 1, 1-A). In addition, emissions associated with BLM Transportation Scenario 3 would be lower than emissions resulting from BLM Transportation Scenario 2, due to the fact that estimates of emissions associated with tanker transit and in-port tanker operations, which would occur in Scenario 3 (in Galveston, Texas), are not included in this analysis.

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VI. POLLUTANT MODELING

Effects of possible Sale No. 53 activities on onshore air quality have been estimated through use of computer simulation modeling. The modeling is based upon the emissions estimates and available data on ambient air quality and meteorology. It does not incorporate beneficial effects of mitigation measures, which are described in Chapter VII.

Two types of point source models were employed -- Gaussian and reactive grid. The models assume different modeling inputs and were used to model different emissions and meteorological events. Gaussian models developed and approved by the U.S. Environmental Protecion Agency (EPA) were used to model ambient concentrations of nitrogen dioxide (NO_2), sulfur dioxide (SO_2), total suspended particulates (TSP) and carbon monoxide (CO) which could result from potential OCS Lease Sale No. 53 activities (EPA, 1978). The RAPT (Reactive Air Pollutant Transport) and IMPACT (Integrated Model of Plumes and Atmospherics in Complex Terrain) models were used to simulate ozone and nitrogen dioxide production from potential emissions of hydrocarbons and nitrogen oxides. RAPT also models inert pollutants such as SO_2 and TSP.

Although Gaussian modeling is less realistic in terms of assumed conditions, it can be effectively used to identify significant pollutant situations. Source-receptor pairs can be quickly assessed to determine emission levels which could result in significant concentration increments downwind. The more refined reactive grid modeling follows pollutants in space and time. As each segment or cell encounters specific background emissions and meteorological conditions, it is introduced into the computation of chemical reactions, diffusion and transport. The physical processes can be described on various scales: the chemical, or particle-interactive scale; the microscale (inches to hundreds of feet) which involves convection and mixing; and the meso or regional scale which descrbes the major movement of emission plumes. The processes on each scale are implemented in the simulation model by simplifying and integrating the several parts. The competence of the model, together with the appropriateness of the scenario, emissions, and ambient conditions determines the overall success of the modeling effort. Refer to Appendix B for a detailed discussion of modeling and model characteristics, both in general, and as they apply to this study.

Computer models can estimate pollutant concentrations to within a factor of two. In general practice, however, modeling results are usually not this precise. Analyses based on worst-case assumptions were used in this study in order to minimize the possibility that impacts would be underpredicted. The major worst-case assumptions are:

- Maximum emission rates were developed by assuming simultaneous operation of likely OCS-related emission sources during peak production years. No emission limitations were assumed beyond those normally expected as part of current best available engineering practice).

- Placement of all emission sources was such that estimated onshore impacts would be maximized. Where possible, OCS sources were located at the 3-mile limit. Mobile sources were placed as close to the shoreline and to fixed offshore emissions sources (to concentrate emissions) as possible.

- o Adverse meteorological conditions included light wind speeds, direct pollutant transport toward shore, and limited mixing of the plume with ambient air when computing short-average concentrations.

- o Most adverse combination of published stack and design parameters (i.e., stack height, exhaust gas temperature, effluent exit velocity, etc.) were chosen to keep the plume near ground level.

- o No absorption of NO_x and SO_x by the ocean surface was assumed, even though these pollutants are soluble in water.

- o Maximum possible background levels were assumed in assessing the potential for violation of air quality standards.

The intent of this worst case analysis is to identify potential problem areas and to evaluate possible cumulative impacts of Sale 53.

A. Long-Term Average Concentrations

1. Applicable Air Pollutants

The only long-term average computed was the annual average since it is the only averaging period in the air quality standards which is longer than one day. The pollutants with annual standards that would be emitted by Lease Sale No. 53 activities are nitrogen dioxide (NO_2), sulfur dioxide (SO_2), and total suspended particulate matter (TSP). All of these pollutants, except for NO_2, are slowly reactive relative to the transport time from near-shore OCS emission sources to onshore receptors. They are treated as inert, however, in the Gaussian modeling.

2. Model Selection, Adaptation and Assumptions

Worst-case Gaussian screening was used to identify short- and long-term inert (or quasi-inert) emission sources and emission levels which could contribute to significant onshore annual and short-term concentrations. The Climatological Dispersion Model (CDM), recommended in the EPA modeling guidelines (EPA, 1978), was chosen for modeling annual averages. CDM, designed for urban applications, is a Gaussian model which determines long-term (monthly, seasonal or annual) quasi-stable pollutant concentrations at any ground-level receptor using average emission rates from point and area sources and a joint frequency distribution of wind direction, wind speed and stability for the same period. Two pollutants may be considered simultaneously, the most frequent application being for sulfur dioxide and particulate matter.

The basic feature of the CDM model is the assumption that, for short time periods, meteorological conditions can be regarded as steady and uniform over the entire area. Since the coastal environment, however, is characterized by winds which rotate from parallel to the shore to onshore, CDM results can overestimate concentrations.

CDM uses urban dispersion coefficients. Since the principal emission sources associated with the Lease Sale No. 53 tracts are beyond the three-mile limit, and most transport and dispersion of pollutants would occur over water, the mechanical turbulence associated with plume dispersion over urban surface roughness is not applicable. The model was therefore modified to remove the urban factors.

Additional discussion of the model, of assumptions, and of model accuracy is presented in Appendix B.

3. Data Requirements

Input to the CDM program consists of meteorological parameters, source parameters and emissions, and source and receptor coordinates. Combinations of point and area sources can be modeled and computations can be performed for any number of receptor points. Outputs of the program consist of the calculated contribution from area and point sources expressed in units of micrograms per cubic meter ($\mu g/m^3$).

The CDM model requires joint frequencies of wind speed and stability data, annually averaged for each of 16 compass directions. The model was run with joint frequency data generated by a STAR program (STability ARray). The data were generated by the National Climatic Center in Asheville, North Carolina, from National Weather Service data. STAR-like data (i.e., meteorological data lacking the stability characterization) were tested for suitability as a substitute data base and found to be adequate. STAR-like data were used for the North Coast Air Basin (Figure III-3). Parameters which were used to compute plume rise (called herein stack parameters) for possible Lease Sale No. 53 emissions sources are listed in Table C-31. Modeling data are tabulated in Appendix C.

4. Levels and Comparisons to Standards

Table VI-1 summarizes annual average worst-case Gaussian modeling results for the five proposed Lease Sale blocks. Highest onshore concentrations are tabulated for the scenarios developed. The first set of three concentrations are based on Scenarios 1, 2 and 3 emissions and represent the highest concentrations attributable to offshore sources in the years with peak emissions of each pollutant. (Refer to Section V.B.2 for a discussion of scenarios.) Offshore gas processing is assumed. There are insignificant differences for results from Scenarios 1, 2, and 3. The next set of concentrations are for Scenario 1A which assumes onshore gas processing. Concentrations from hypothesized onshore gas processing plants are tabulated in terms of highest concentrations at distances of 1,650 feet and 3,300 feet. The direction to the highest concentrations is also listed. The stack parameters [taken from the Environmental Impact Report on pipeline conveyance alternatives for Platform Grace in Santa Barbara Channel (Woodward-Clyde, 1978) and listed in Table C-31 of Appendix C] result, on average using annualized meteorology, in a low plume rise and maximum concentrations near the gas processing plant. It is for this reason that computations for short distances from the gas processing plant are stressed in the analysis.

The data in Table VI-1 are based on the USGS mean gas and petroleum resource estimates. For each zone, the scenarios and years with the highest estimated emissions were chosen for modeling. Modeling assumptions resulting in highest computed concentrations were also chosen for each zone. The modeling probably overpredicts concentrations, perhaps by as much as an order of magnitude. Computed concentrations would be lower for other years. Figures V-1 to V-29 display the temporal change in offshore emissions of total suspended particulate matter and of oxides of nitrogen and sulfur, and provide a perspective on the relative duration of the period of time with significant emission rates.

Modeling assumptions, input data, and significance of modeled concentrations are described in the following subsections.

a. Eel River

1. Input Data and Procedures

a) Background Concentrations

Inert (or quasi-inert) modeling allows the simple addition of modeled levels to ambient concentrations.

The data from Chapter IV (Section IV.B.2.a for the Eel River Valley) serve as the basis for estimating future background concentrations. Annually averaged background levels of TSP, SO_2, and NO_2 are of interest in assessing the effects of Lease Sale activities on meeting air quality standards and other regulations. Based on limited data, the California Air Resources Board (CARB) estimates that the nitrogen dioxide standards will not be violated through 1995; but they do not provide estimates of future ambient levels (CARB, 1978).

The major sources of sulfur dioxide in Humboldt County are power plants. Since monitoring of SO_2 downwind of these plants is inadequate and SO_2 emissions in the county are projected to increase by 80 percent, it is not clear that the SO_2 air quality standard will be met in the 1990s with existing control strategies (CARB, 1978).

CARB estimates that suspended particulate matter air quality standards will continue to be violated through 1995. Statistically valid data for 1974 from the Samoa monitor (137 $\mu g/m^3$, annual geometric mean) greatly exceed the national primary (75 $\mu g/m^3$) and secondary (60 $\mu g/m^3$, and state (60 $\mu g/m^3$) annual air quality standards. Other statistically significant monitoring data taken at Arcata and Eureka are below the annual TSP standards.

In summary, future year background levels of NO_2 and SO_2 should be below standards. It should be assumed that annually averaged background levels of TSP will be close to the levels specified by state and federal annual air quality standards.

b) Meteorological Input

Joint frequency meteorological data compiled by Pacific Gas and Electric Company at Eureka were used in place of STAR program data (California Department of Water Resources, 1978). These data lack a stability characterization. For each compass direction, the frequency of occurrence of winds within each of several wind speed ranges was computed. Shoreline data were chosen because they should produce greater onshore concentrations than similar joint frequency data collected by the U.S. Navy offshore (U.S. Navy, 1976a); the offshore data have a higher proportion of winds parallel to the coast. The use of alternate data sets was tested. For example, similar onshore data for San Francisco using assumed stability class E (stable) and full STAR data were found to give modeling results which differed by only 10 percent (for further discussion see Section VI.A.4.d, Santa Cruz, below). Input data for modeling are compiled in Appendix C. The joint frequency data are displayed in Figure C-1.

Table VI-1. SUMMARY OF HIGHEST COMPUTED ANNUAL AVERAGE CONCENTRATIONS[1]

Zone	Highest Onshore Concentration (ug/m^3) Associated With: Offshore Activities[2] (Scenarios 1, 2, & 3) NO_2	SO_2	TSP	Onshore Gas Processing Plant[3] (Scenario 1A) NO_2	SO_2	TSP	Direction to Highest Concentrations (degrees)
Eel River[4]	2.9	1.1	0.14		12.6/5.9		180
Pt. Arena[4]	0.87	1.1	0.13	12.3/5.6	13.0/5.9	1.2/0.5	150
Bodega[4]	4.4	0.35	0.23				
Santa Cruz	1.0	0.15	0.07	7.4/3.3	11.9/5.2	0.17/.07	120
Santa Maria	1.5	0.7	0.1	22.5/10.2	26.5/11.9	0.27/0.12	120
National AAQS[5]	100	80	75&60	100	80	75&60	
California AAQS[5]			60			60	
DOI/PSD Increments[5]		20	19		20	19	
DOI/PSD[5] Significance Level	1	1	1	1	1	1	

1. Directions to the highest computed concentrations in the vicinity of onshore gas processing plants are measured clockwise from true north in degrees. Abbreviations are nitrogen dioxide (NO_2), sulfur dioxide (SO_2), and total suspended particulate matter (TSP).
2. This value is the highest concentration contour which passes over land, calculated using the CDM program for Scenarios 1, 2, or 3. Offshore gas processing assumed.
3. The two values separated by a slash represent the highest concentrations calculated at distances of 0.5 and 1.0 kilometer, respectively. Stack parameters are taken from Woodward-Clyde (1978); see text and Table C-31.
4. These zones were modeled using a worst case assumption of emissions distribution, i.e., all emissions were concentrated into a single point source at the three-mile limit.
5. National and California Ambient Air Quality Standards (AAQS) are listed in Table III-1. The lower numbers presented here are secondary standards. Proposed Department of the Interior (DOI) significance levels and maximum allowable increments are listed in Table VI-2. DOI's proposed maximum increases are the same as those used by the Environmental Protection Agency in its Prevention of Significant Deterioration (PSD) program. DOI increments apply to offshore sources, whereas PSD increments apply to onshore sources.

c) Emissions and Modeling Considerations

Annually averaged emissions are compiled by source in Tables C-2 through C-4 (Appendix C) for the years with highest estimated emissions. Emissions in Tables C-1 through C-25 (Appendix C) are tabulated for peak activities in peak emissions years. Annual average modeling uses annualized emissions expressed in units of tons per year for all activities described in the tables, excepting in-port emissions at a distance from the Lease Sale No. 53 zone.

Any future distribution of Lease Sale emissions sources on and near the Eel River tracts are presently unknown. A worst-case geographical assumption was emphasized. This consisted of a screening run of CDM where all Eel River zone OCS emissions are concentrated in a single point source at the three mile limit. Table C-33 (Appendix C) summarizes the emissions rates used in the screening modeling which was designed to result in maximum possible concentrations. A comparison of a similar screening run with a realistic distribution of emissions for the Santa Cruz OCS zone (Section VI.A.4.d, below) showed that the simplified procedure gave higher concentrations by a factor of 9.5. The relative difference in magnitude between modeling of a realistic emissions spread and of the single point emissions source for the Eel River zone would be less than that computed for the Santa Cruz zone case since the Eel River zone is geographically smaller than the Santa Cruz zone. Nevertheless, a worst case geographical assumption for the Eel River zone increases annually averaged computed concentrations considerably.

ii. Air Pollutant Concentrations

The single point source screening run resulted in annual average emissions concentrations of 2.9 $\mu g/m^3$ of NO_2, 1.1 $\mu g/m^3$ of SO_2, and 0.14 $\mu g/m^3$ of TSP at the shoreline for emissions from Scenarios 1, 2, and 3. These are maximal levels based on the years with highest emissions and employ a strongly worst case geographical assumption of the emissions spread. O_2, SO_2, and TSP are the only air quality contaminants for which annual average air quality standards apply. Nitrogen oxides were asumed to consist entirely of NO_2 at receptor points. The computed onshore concentration of NO_2 represents 2.9 percent of the annual NO_2 air quality standard (Table III-1) of 100 $\mu g/m^3$. The modeling increment when added to the future background level is predicted to be below the air quality standard. The SO_2 increment represents 1.4 percent of the federal primary standard (80 $\mu g/m^3$). The future SO_2 background level downwind from power plants may be near the standard, making even this small an increment a concern. The TSP increment represents 0.2 percent of the primary TSP standard of 75 $\mu g/m^3$. The background TSP level may approach the standard in the Eel River Valley in the 1980s, making any additional increments a concern.

Under the Department of the Interior's (DOI's) proposed OCS air emission regulations, both the SO_2 and NO_2 concentrations exceed the significance levels and are therefore considered "significant". (See Chapter III for an explanation of applicable Rules and Regulations.) With more refined modeling, the SO_2 concentration would drop to a level of insignificance, and probably the NO_2 level would also. Since these concentrations as modeled do not exceed the maximum allowable increases for a Class II area and since the computed high concentrations would result from temporary platform installation activities, Best Available Control Technology (BACT) would likely be required, provided that these concentrations would not interfere with the maintenance of national ambient air quality standards (NAAQS). The TSP concentration is not "significant" and controls would not be required.

Gaussian modeling can be quite inaccurate (see Appendix B). Predictions of concentrations can be in error by a factor of ten, more often high than low. The CDM model and the screening computations scheme are both designed to overpredict annual concentrations. The CDM model could overpredict by about a factor of two and the simplified geometric scheme by about a factor of six. Therefore, the concentrations calculated by screening should be considered to be on the high side, and the controls indicated above might not actually be required.

The emissions (Table C-33, Appendix C) from the onshore gas processing plant hypothesized in Scenario 1A were also modeled using CDM. Concentrations were analyzed for dependence on distance from the plant. Modeling using published stack parameters (Woodward-Clyde, 1978) resulted in highest concentrations near the plant. Stack height and volume flow from the hypothesized gas processing plant are quite low; and the wind speeds, on an annual average, are sufficient to result in relatively low plume rise. Concentrations were computed over three concentric circles with radii of 1,650 feet (0.5 kilometer), 3,300 feet and 5,280 feet. Again, Pasquill stability class E, together with the Eureka joint frequency meteorological data, were used to represent worst-case conditions. The highest simulated concentrations of SO_2 were 12.6, 5.9, and 3.4 $\mu g/m^3$, respectively, for the three distances, at a compass direction of 180° (true north being 0°). In the seaward direction from the plant (or compass direction of 270°), the concentrations were 2.4, 1.2, and 0.7 $\mu g/m^3$, respectively. These concentrations are about 20 percent of the maximum concentrations above. The maximum modeled concentration represents 16 percent of the annual primary standard and 63 percent of the annual PSD Class II Area limit for all projects in the vicinity. Concentrations would decrease rapidly with distance from the gas plant. The emissions modeled are for the peak year of Lease Sale No. 53 production.

The computations above represent a worst-case modeling exercise using USGS-generated production estimates, EPA-approved Gaussian models, stack parameters for an existing gas plant at Carpenteria in Santa Barbara County, and projected emissions calculated without application of control technology. If an onshore plant would be proposed by a developer to process OCS Lease Sale No. 53 gas production following exploratory drilling, more detailed modeling would be required and would likely be subject to BACT requirements. The modeling would use engineering design data and production estimates generated by the developer, and would take into account site-specific meteorological and terrain factors, thereby yielding more representative results.

b. Point Arena

CDM modeling of annual average concentrations from the Point Arena and Eel River OCS zones were conducted in a similar manner. As a result, the discussion of the Point Arena modeling is brief. Refer to Section VI-A.4.a (Eel River), immediately above, for a discussion of common methodologies.

i. Input Data and Procedures

Refer to Section VI.A.4.a, immediately above, and Section IV.B.2.b for a broader discussion of air quality data.

CARB estimates that future levels of NO_2 will be below the NO_2 air quality standards (CARB, 1978). There is expected to be an insignificant increase in projected SO_2 emissions in Mendocino County and a consequent margin of safety in considering future background levels of SO_2. All the highest and second-highest TSP concentrations in the Air Basin have been recorded in Mendocino County. Therefore, there is expected to be even less tolerance for new TSP emissions in areas adjacent to the Pt. Arena OCS zone than is the case near the Eel River zone.

Meteorological data compiled by Pacific Gas and Electric Company at Point Arena were used in place of STAR data (unavailable) in CDM modeling (California Department of Water Resources, 1978). The data are tabulated in Figure C-2 (Appendix C).

Annually averaged NO_x, SO_2, and TSP emissions are compiled in Tables C-7 through C-9 (Appendix C) for years with estimated highest emissions. Table C-34 (Appendix C) summarizes emissions rates used in CDM screening for computed maximum possible concentrations.

ii. Air Pollutant Concentrations

The point source screening resulted in computed annual average concentrations of 0.87 $\mu g/m^3$ of NO_2, 1.1 $\mu g/m^3$ of SO_2, and 0.13 $\mu g/m^3$ of TSP at the shoreline for Scenarios 1, 2, and 3. These values represent 0.87, 1.4, and 1.7 percent of the respective annual air quality standards. Gaussian modeling is not precise, and these computed values are most probably overpredictions, perhaps by an order of magnitude. These are maximal levels based on the years with highest emissions, and employ a decidedly worst case geographical assumption of the emissions spread. There is little tolerance for additional SO_2 in the Point Arena area and essentially none for additional TSP. Nitrogen dioxide, SO_2 and TSP are the only pollutants for which annual average air quality standards apply. Taking into account the estimated future background levels and the degree to which the models overpredict, it appears unlikely that OCS activities would cause an annual air quality standard to be exceeded, even in the peak emission year.

The modeled SO_2 concentration increment marginally exceeds the proposed DOI significance level. However, more refined modeling would result in a computed concentration well below the significance criterion. The TSP and NO_2 concentrations are below DOI's proposed significance levels. Hence, it appears that under DOI's proposed regulations, controls would not be required for TSP, NO_2 and SO_2 emissions.

The onshore gas processing plant hypothesized in Scenario 1A was also modeled using CDM. Highest concentrations, on an annual average, were found to be near the gas plant. Concentrations were computed over three concentric circles with radii of 1,650 feet, 3,300 feet and 5,280 feet. The highest modeled concentrations of NO_2 were 12.3, 5.6, and 3.2 $\mu g/m^3$, respectively for the three distances, at a compass direction of 150° (true north being 0°). In the seaward direction from the plant (compass direction of 270°), the concentrations were 1.6, 0.8, and 0.5 $\mu g/m^3$, respectively. These concentrations are about 15 percent of the maximum concentrations above. The maximum modeled

concentration represents 12 percent of the annual primary standard. Concentrations would decrease rapidly with distance from the gas plant. The emissions modeled are for the peak year of Lease Sale No. 53 production.

The highest modeled SO_2 concentrations were 13.0, 5.9, 3.3 $\mu g/m^3$, respectively (also at a compass direction of 150°). The maximum modeled concentration represents 12 percent of the annual standards and 65 percent of the allowed annual average PSD Class II Area increment for all projects in the vicinity. Concentrations would decrease rapidly with distance from the gas plant. The emissions modeled are for the peak year of production.

The highest modeled TSP concentrations were 1.2, 0.5, and 0.3 $\mu g/m^3$. The maximum modeled concentration represents 1.6 percent of the federal annual primary standard and 6 percent of the maximum allowable concentration increase for a Class II area. Careful site selection for the gas plant could prevent violation of the annual standards.

c. Bodega

i. Input Data and Procedures

The San Francisco Bay Area Air Basin is in nonattainment of the federal annual particulate matter (TSP) (75 $\mu g/m^3$ primary and 60 $\mu g/m^3$ secondary) air quality standards. The Air Basin should meet the federal annual nitrogen dioxide and sulfur dioxide standards of 100 $\mu g/m^3$ and 80 $\mu g/m^3$, respectively. Refer to Figures IV-25, IV-26, and IV-29 for spatial distributions of present annual average concentrations of NO_2, SO_2, and TSP, respectively. Refer to Section IV.B.2.c for a general discussion of San Francisco Bay Area air quality.

The CDM model was run with joint frequency data generated by a STAR program. STAR data were compiled from National Weather Service data collected on the San Francisco peninsula at Station No. 23234.

The point source, worst-case emissions distribution methodology, which was used for the Eel River and Point Arena zones (and described above), was also used for the Bodega zone modeling. Offshore emissions were concentrated at a single point at the three mile limit and concentrations calculated at a distance of three miles. This resulted in maximum possible computed concentrations at the shoreline. Table C-35 displays modeling emissions based on tabulations in Tables C-12 through C-14 (Appendix C) for the peak emission years.

ii. Air Pollutant Concentrations

The maximum computed onshore concentrations were 4.4 $\mu g/m^3$ of NO_2, 0.35 $\mu g/m^3$ of SO_2, and 0.23 $\mu g/m^3$ of TSP for Scenarios 1, 2, and 3. The maximum NO_2 concentration represents 4.4 percent of the federal annual primary air quality standard of 100 $\mu g/m^3$ and exceeds the DOI significance level of 1 $\mu g/m^3$. More refined modeling would result in a computed concentration near the significance level. These are temporary impacts from platform installations. The maximum SO_2 concentration represents 0.4 percent of the federal annual standard (80 $\mu g/m^3$) and 1.8 percent of DOI's proposed maximum allowable increase for a Class II Area. The maximum TSP concentration represents 0.3 percent of the federal annual primary standard (75 $\mu g/m^3$), 0.4 percent of the secondary standard (60 $\mu g/m^3$), and 1.2 percent of DOI's proposed maximum allowable

increase for a Class II Area. Computed concentration increments of SO_2 and TSP are less than DOI's proposed significance criterion of 1 $\mu g/m^3$ (Table VI-2). Point Reyes (a promontory on the coast ten miles or more from the Bodega zone) and Muir Woods (a few miles further south) are EPA Class I areas, but are too distant to be affected by potential emissions originating from this zone. Highest TSP background levels (refer to Figure IV-28) would occur inland near Livermore. It is likely that the annual background TSP level in Marin County, near the Bodega zone, will be considerably below the annual standards during the 1980's, and, therefore, violations of TSP standards are unlikely. The computed concentrations are maximal levels based on years with highest emissions and employ a strongly worst-case geographical assumption of the emissions spread. Nitrogen dioxide, SO_2, and TSP are the only pollutants for which annual average air quality standards apply.

Under the DOI's proposed OCS air emission regulations only the worst-case NO_x emissions modeling results from this tract are considered significant. Hence, BACT for NO_x could be required while no controls would be required for SO_x and TSP.

It is hypothesized that the unused Bodega zone natural gas would be reinjected into wells. Therefore, the only onshore facilities would be dedicated to crew and supply boat operations and would be located in San Francisco Bay. Emissions concentrations would be insignificant when annually averaged. Tanker unloading emissions in the Bay are anticipated even without Bodega zone development since petroleum from other sources would then pass through these petroleum terminals. Tanker operations to and from the Bodega zone would, therefore, have no additional effect upon annual average concentrations in the Bay. Annual average concentrations of TSP exceeded 50 $\mu g/m^3$ in some parts of the Bay in 1975 (Figure IV-29); and there is little tolerence for additional emissions.

d. Santa Cruz

i. Input Data and Procedures

a) Background Concentrations

Ambient levels of nitrogen dioxide (NO_2), sulfur dioxide (SO_2) and particulate matter (TSP) are currently below air quality standards along the coast in the North Central Coast Air Basin. It is anticipated that annually averaged pollutant levels there will remain below standards in future years. The Santa Cruz zone is also in immediate proximity to the southern part of the San Francisco Bay Area Air Basin. Future background levels of NO_2, SO_2, and TSP should be below Federal annual air quality standards near the coast opposite the Santa Cruz zone.

b) Meteorological Input

The model was run with STAR data derived from a computer analysis of meteorological data collected on the San Francisco peninsula. These data were also used for the Bodega zone computations described in the previous section.

Table VI-2. DEPARTMENT OF THE INTERIOR'S PROPOSED SIGNIFICANCE LEVELS AND MAXIMUM GROUND LEVEL INCREMENTAL INCREASES ($\mu g/m^3$)

Pollutant[1]	Maximum Allowable Increase Class I[1]	Class II[1]	Class III[1]	Significance Level[2]	NAAQS[3]
Sulfur Dioxide:					
Annual	2	20	40	1	80
24 Hour	5	91	182	5	365
3 Hour	25	512	700	25	1,300[4]
Total Suspended Particulate Matter:					
Annual	5	19	37	1	75
24 Hour	10	37	75	5	260
Carbon Monoxide:					
8 Hour				500	10,000
1 Hour				2,000	40,000
Nitrogen Dioxide:					
Annual				1	100

1. The Department of the Interior's proposed maximum increases are the same as those used by the Environmental Protection Agency in its Prevention of Significant Deterioration (PSD) program.

2. OCS air emissions sources are exempt from further review and controls if their modeled onshore pollutant concentrations are below these significance levels. Volatile organic compound emissions are significant if they are released within a 36-hour travel time of the shore. Chapter III provides a full discussion of applicable air quality rules and regulations.

3. NAAQS - Primary National Ambient Air Quality Standards.

4. Indicates a secondary standard.

c) Emissions and Modeling Considerations

Annually averaged emissions are compiled by source in Tables C-17 through C-19 (Appendix C) for the years with estimated highest emissions. Concentrations onshore which would result from these emissions sources would depend on the geographic distribution of the sources within the Santa Cruz zone. Lowest concentrations would result if the sources were scattered as uniformly as possible along the western edge of the zone; this assumption is not realistic. Equally unrealistic is the highest concentration assumption of all emissions lumped into a single point source at the three mile limit. This hypothesized distribution does have the merit of defining the computationally highest concentrations relative to the unknown distribution of sources which would result from leasing within the Santa Cruz zone. This worst case was modeled using CDM. Also modeled was an hypothesized, but reasonably realistic, distribution of the emissions sources defined in the emissions tables (C-17 through C-19, Appendix C) and suggested by the reactive modeling effort (as described in Section VI.C, below).

Figure VI-1 displays the hypothesized locations of OCS Lease Sale No. 53 facilities and transit emissions areas on the Santa Cruz zone tracts, together with the grid structure used in modeling. Table C-36 (Appendix C), summarizes the annual emissions levels used in the modeling effort. The numbering of the point and area sources in Figure VI-1 is keyed to emission rates in Table C-36. Up to nine platforms and other structures are assumed.

ii. Air Pollutant Concentrations

Isopleths of computed annual concentrations of nitrogen dioxide (NO_2) are illustrated in Figure VI-2. NO_2 and SO_2 emissions from gas processing were computed twice, as offshore emissions under Scenarios 1, 2, and 3, and as onshore emissions under Scenario 1A. Nitrogen oxides were assumed to consist entirely of NO_2 at the receptor points. These results are for the U.S. Geological Survey mean petroleum and gas estimates. These are maximal levels based on the year with highest nitrogen oxides emissions from platform installation activities.

Computed onshore concentrations of NO_2 are about 1 $\mu g/m^3$, or less. This represents up to one percent of the annual nitrogen dioxide air quality standard of 100 $\mu g/m^3$ and is roughly equal to DOI's proposed significance level of 1 $\mu g/m^3$. The modeling assumed that all nitrogen oxides would be oxidized to nitrogen dioxide; this is a worst-case assumption. Also, no surface absorption was assumed over the ocean although nitrogen dioxide is quite soluble in water. Assumption of total absorption at the surface would reduce the calculated concentrations by up to a factor of two.

As mentioned previously, computed concentrations derived by Gaussian models can be quite inaccurate (see Appendix B). In compensation, Gaussian models are biased to overpredict. Biasing was also employed in the computational assumptions. Nevertheless, the modeling, the resource estimate and the emissions estimates, in combination, would have to underestimate levels by much more than an order of magnitude to result in the potential for adverse violations of the annual nitrogen dioxide air quality standards.

Figure VI-3 illustrates isopleths of computed annually averaged concentrations of sulfur dioxide. Onshore computed concentrations are 0.15 $\mu g/m^3$, or less, except for an area east of the hypothesized gas plant under Scenario 1A

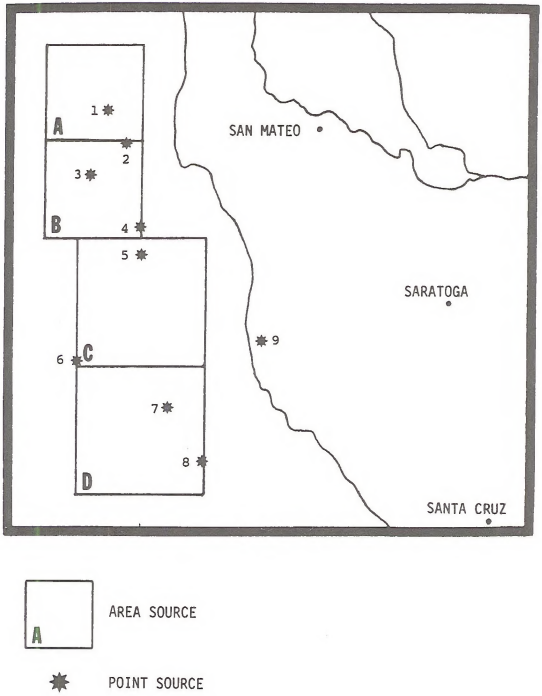


Figure VI-1. EMISSIONS LOCATIONS IN MODELING ANNUAL AVERAGES FOR THE SANTA CRUZ OCS ZONE

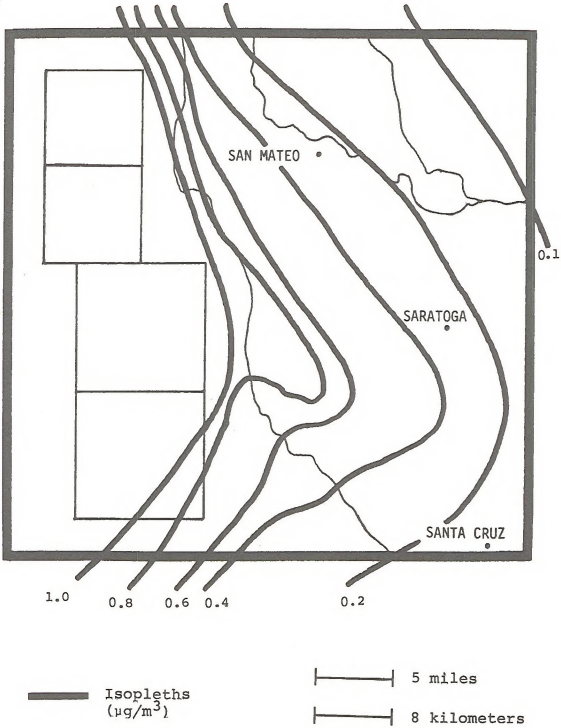


Figure VI-2. ISOPLETHS OF NO_2 FOR COMPUTED ANNUAL AVERAGES, SANTA CRUZ OCS ZONE

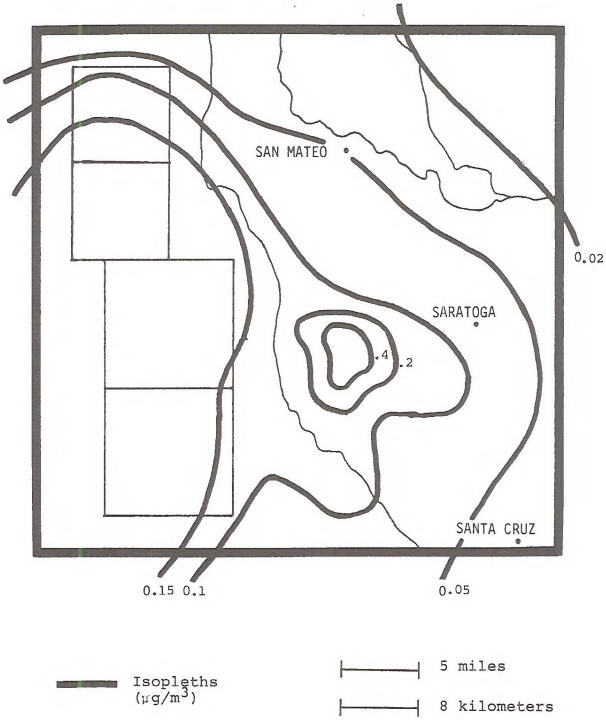


Figure VI-3. ISOPLETHS OF SO_2 FOR COMPUTED ANNUAL AVERAGES, SANTA CRUZ OCS ZONE

This is well below DOI's proposed significance level of 1 $\mu g/m^3$. Computed onshore concentrations represent up to 0.2 percent of the annual air quality standards of 80 $\mu g/m^3$. These are maximal levels based on the year with highest emissions.

Computed onshore concentrations of particulate matter represent up to 0.1 percent of the annual primary air quality standard of 75 $\mu g/m^3$, and are well below the proposed DOI significance level. Contours for TSP are similar to those for nitrogen dioxide (Figure VI-2). Nitrogen dioxide, SO_2, and TSP are the only air quality contaminants for which annual average air quality standards apply.

The onshore area, except for Ventana (Big Sur), has been designated by EPA as a Class II Area. Consequently, the maximum allowable pollutant concentration increases, as proposed by DOI are 20 $\mu g/m^3$ of SO_2 and 19 $\mu g/m^3$ of TSP. On the basis of worst case modeling results, estimated Lease Sale No. 53 increments in the onshore area near the Santa Cruz zone could represent as much as 0.8 percent of the allowed SO_2 increment and 0.4 percent of the allowed TSP increment in the peak emissions years. Class I Area PSD increments apply to Ventana. The annual increments are 5 $\mu g/m^3$ for TSP and 2 $\mu g/m^3$ for SO_2 (Table VI-2). These increments are larger than the proposed DOI significance levels and are not exceeded by the computed concentrations of TSP and SO_2.

An arbitrary distribution of platforms, other structures and transit emissions were assumed in CDM modeling (refer to Figure VI-1). In order to estimate the maximum effect of assumptions of geographical distribution, the worst case distribution was also modeled. This consists of concentrating all OCS emissions for the Santa Cruz zone in a single point source at the three mile limit. Concentrations were computed using CDM in an arc three miles from the point emissions source.

Highest computed levels were 9.5 $\mu g/m^3$ of NO_2 and 3.4 $\mu g/m^3$ of SO_2. These results are larger than the concentrations computed for distributed sources (Figure VI-1) by a factor of ten or more, and are well above DOI's proposed significance levels. Specific variations in implementation of a reasonable geographical distribution will result in variations in computed levels.

The onshore gas processing plant hypothesized in Transportation Scenario 1A was also modeled using CDM. Highest concentrations, when annually averaged, were found to be near the gas plant. Concentrations were computed over three concentric circles with radii of 1,650 feet, 3,300 feet and 5,280 feet.

The highest simulated concentrations of NO_2 were 7.4, 3.3, and 1.8 $\mu g/m^3$, respectively for the three distances, at a compass direction of 120° (true north being 0°). In the seaward direction from the plant (compass direction of 270°), the concentrations were 0.96, 0.41, and 0.22 $\mu g/m^3$, respectively. These concentrations are about 13 percent of the maximum concentrations above. The maximum modeled concentration represents seven percent of the annual primary standard. Concentrations would decrease rapidly with distance from the gas plant. Concentrations at greater distances appear as distortions of the contours near the plant, as displayed in Figure VI-2. The emissions modeled are for the peak year of Lease Sale No. 53 production.

The highest modeled SO_2 concentrations are 11.9, 5.2, and 2.9 $\mu g/m^3$, respectively (also at a compass direction of 120°). The maximum modeled concentration represents 15 percent of the annual standard and 60 percent of the annual PSD Class II Area limit for all projects in the vicinity. Concentrations would decrease rapidly with distance from the gas plant. Concentrations at longer distances appear as significant modifications of low level contours to the east of the gas plant, as displayed in Figure VI-3.

The modeled NO_2 and SO_2 levels are above EPA's significance levels and the plant would be subject to a full PSD review. Hence, the facility would be required to employ BACT for NO_x and SO_x, and comply with other PSD provisions.

The highest modeled TSP concentrations were 0.17, 0.07 and 0.04 $\mu g/m^3$, respectively. The maximum modeled concentration represents 0.2 percent of the annual standard, and is well below EPA's significance level for TSP.

e. Santa Maria

i. Input Data and Procedures

The annual average for nitrogen dioxide in Santa Barbara in recent years has been as high as 80 $\mu g/m^3$, or 80 percent of the federal standards. Annual averages elsewhere in the counties of San Luis Obispo and Santa Barbara have been lower. It is anticipated that annually averaged background levels of NO_2 in future years will be below standards by a modest margin.

Annually averaged sulfur oxide levels are currently below federal standards and are anticipated to remain at acceptable levels. Highest levels in San Luis Obispo and Northern Santa Barbara Counties occur at Nipomo. Twenty-four hour averages have been as high as 70 percent of the California standard (131 $\mu g/m^3$).

The federal annual secondary particulate matter standard (60 $\mu g/m^3$) has been exceeded in recent years in Paso Robles, Santa Maria, Lompoc, and Santa Barbara. The primary standard (75 $\mu g/m^3$) has been exceeded in Santa Maria and Lompoc during recent years. Levels have been lower along the coast. It is reasonable to assume that annually averaged TSP concentrations along the coast will remain somewhat below standards.

The CDM model was run with STAR data derived from a computer analysis of meteorological data collected at Station No. 93215 at Point Arguello. Measurements from this site should be representative of shoreline meteorology along the coast north of Point Conception. Use of shoreline winds should result in overestimated onshore transport from the Santa Maria zone due to differences in offshore and shoreline winds (winds rotate from parallel to the shore to onshore).

Annually averaged emissions are compiled by source in Tables C-22 through C-24 (Appendix C), for the estimated years with highest emissions. Figure VI-4 displays the hypothesized locations of OCS Lease Sale No. 53 facilities and transit emissions areas on the Santa Maria zone tracts, together with the grid structure used in CDM modeling. Table C-37 (Appendix C) summarizes the annual emissions levels used in the modeling effort. The numbering of the point and area sources in Figure VI-4 is keyed to emission rates in Table C-37. Fourteen platforms and other structures are assumed.

ii. Air Pollutant Concentrations

Isopleths of computed annual concentrations of nitrogen dioxide are illustrated in Figure VI-5. NO_2 and SO_2 from gas processing were computed twice, as offshore emissions for Scenarios 1, 2, and 3, and as onshore emissions for Scenario 1A. Nitrogen oxides were assumed to consist entirely of NO_2 at the receptor points. These results are for the USGS mean gas and petroleum resource estimates and anticipated year with highest nitrogen oxide emissions from platform installation activities.

Computed onshore concentrations of NO_2 are 1.5 $\mu g/m^3$, or less, which represents up to 1.5 percent of the annual nitrogen dioxide air quality standard of 100 $\mu g/m^3$, and is above DOI's proposed significance level. It was assumed that all NO_x would be oxidized to NO_2 and that no surface absorption of NO_2 or SO_2 would occur. These are worst case assumptions.

Figure VI-6 illustrates isopleths of computed annually averaged concentrations of sulfur dioxide. Onshore computed concentrations are 0.7 $\mu g/m^3$, or less, except for an area to the southeast of the gas processing plant hypothesized in Scenario 1A.

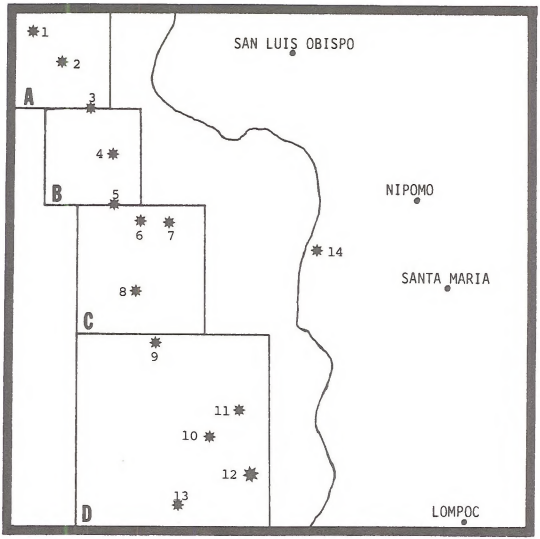
Computed onshore concentrations represent up to 0.9 percent of the annual primary air quality standard of 80 $\mu g/m^3$. These are maximal levels based on the year with highest emissions, but are still below the proposed DOI significance levels.

Computed onshore concentrations of particulate matter represent up to 0.1 percent of the annual primary standard of 75 $\mu g/m^3$, and are below DOI's proposed significance levels. Contours for TSP are similar to those for NO_2 (Figure VI-5). Nitrogen dioxide, SO_2, and TSP are the only air quality contaminants for which annual average air quality standards apply.

The onshore area has been designated by the EPA as a Class II Area. Consequently, the maximum allowable increases under the proposed DOI regulations are 20 $\mu g/m^3$ of SO_2 and 19 $\mu g/m^3$ of TSP. Worst case CDM modeling results in project increments of as much as 3.5 percent of the SO_2 increment and 0.5 percent of the TSP increment in the peak emissions years. Increments are less further inland and in other years.

The onshore gas processing plant hypothesized in Scenario 1A was also modeled using CDM. Highest concentrations, when annually averaged, were found to be near the gas plant. To assess maximum levels, concentrations were computed over three concentric circles with radii of 1,650 feet, 3,300 feet, and 5,280 feet.

The highest simulated concentrations of NO_2 were 22.5, 10.2, and 5.8 $\mu g/m^3$, respectively, for the three distances, at a compass direction of 120° (true north being 0°). In the seaward direction from the plant (compass direction of 270°), the concentrations were 10.4, 5.1, and 3.1 $\mu g/m^3$, respectively. These concentrations are about 51 percent of the maximum concentrations above. The maximum modeled concentration represents 23 percent of the annual primary standard. Concentrations would decrease rapidly with distance from the gas plant. Concentrations at longer distances appear as significant modifications



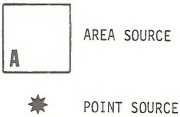


Figure VI-4. EMISSION LOCATIONS IN MODELING ANNUAL AVERAGES FOR THE SANTA MARIA OCS ZONE

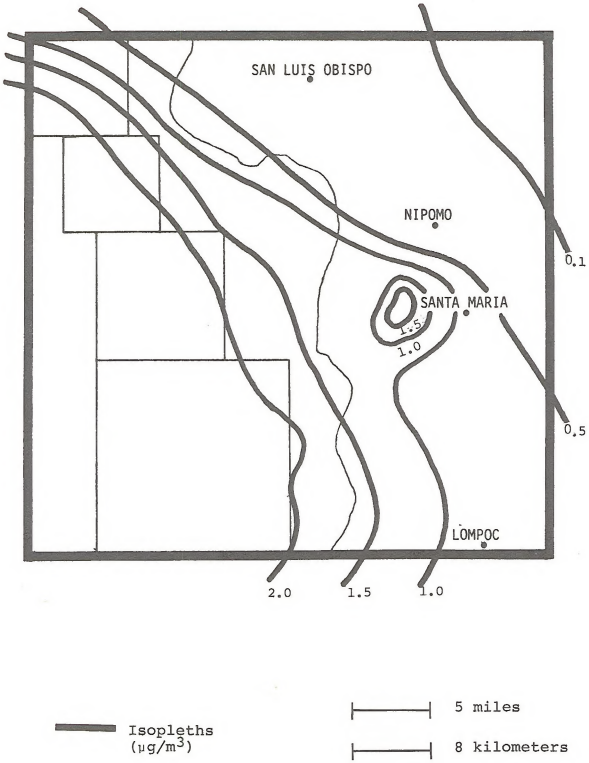


Figure VI-5. ISOPLETHS OF NO_2 FOR COMPUTED ANNUAL AVERAGES, SANTA MARIA OCS ZONE

of contours to the southeast of the gas plant, as displayed in Figure VI-5. The emissions modeled are for the peak year of Lease Sale No. 53 production.

The highest modeled SO_2 concentrations are 26.5, 11.9, and 6.8 $\mu g/m^3$, respectively (also at a compass direction 120°). The maximum modeled concentration represents 28 percent of the annual standard and 139 percent of the annual PSD Class II Area limit for all projects in the vicinity. Concentrations would decrease rapidly with distance from the gas plant. Concentrations at greater distances appear as significant modifications of contours to the southeast of the gas plant, as displayed in Figure VI-6. The emissions modeled are for the peak year of production.

The highest modeled TSP concentrations were 0.27, 0.12, and 0.07 $\mu g/m^3$, respectively at the three distances. The maximum modeled concentration represents 0.4 percent of the annual primary standard and 1.4 percent of the PSD limit.

Both the modeled NO_2 and SO_2 emissions for the gas processing plant are above EPA's significance levels and therefore a full PSD review would be required. The plant would likely be required to use BACT and further possible controls. TSP emissions are below the EPA significance levels, but would still be subject to PSD review, since the plant's NO_2 and SO_2 emission concentrations exceed EPA's significance levels.

B. Modeling of Short-Term Concentrations

1. Applicable Air Pollutants

The OCS emissions of concern for short-term concentrations (one day or shorter averages) are nitrogen dioxide, sulfur dioxide, carbon monoxide, and particulate matter. Hydrogen sulfide (H_2S) can be a problem under some circumstances of petroleum extraction and processing (particularly petroleum refining). Anticipated offshore H_2S emissions from possible Lease Sale No. 53 activities would be too low to result in significant concentrations onshore and were, therefore, not modeled. Emissions of concern are in fact slowly reacting. A worst case assumes that all the nitric oxide (NO) emissions are converted to NO_2 prior to reaching receptor points, that all the other pollutants do not chemically convert to other species, and that there is no fallout or surface absorption during transport and dilution. Nitrogen and sulfur dioxides actually react strongly with the ocean surface and are absorbed. Nitrogen oxides in the RAPT modeling (discussed below) are treated as reactive; they are constituents of complex photochemistry during transport.

The results presented below focus on worst cases. For such, low dispersion is mandatory. Thus, the impact from each localized facility will be independent and the analyses are focused on individual localized emissions events (combinations of platform operations, support activities, etc.) rather than emission scenarios.

Though short term standards call for 24, 8, 3 and 1 hour averages, these analyses are focused on 1 hour worst cases, since difficulties arise in attempting to project the length of time future support activities will require boats at a platform. Instead, air pollution considerations are used to relate

the longer 24, 8 and 3 hour averages to the fundamental one hour worst case. This will provide an overestimate of potential impacts since the emissions variability from maximum is not fully taken into account.

2. Selection of Models

Inert pollutants were modeled in two ways in this study to derive short-term average concentrations. One modeling approach used the EPA-approved Gaussian PT series models. Worst case assumptions were used to obtain a maximum estimate for onshore concentrations from offshore and onshore emissions sources. Assumptions included a low wind speed, steady wind with most direct transport to shore and very high emissions rates from assuming that most support vessels during the modeling period are clustered around the platform or other point sources. Since the proprietary photochemical plume model RAPT permits the modeling of an inert pollutant, it was used as an alternative to Gaussian modeling. The RAPT model allows a much more realistic worst-case modeling trajectory. Refer to Appendix B for additional discussion of models.

a. PTMAX, PTDIS, and PTMTP

The PT-series programs involve relatively simple applications of the Gaussian concept. They assume that concentrations resulting from inert pollutants emitted at different locations do not interact and can be independently added at the receptor. This concept is generally accepted but has never been rigorously justified. Gaussian modeling is basically statistical and phenomenological.

i. Data Requirements

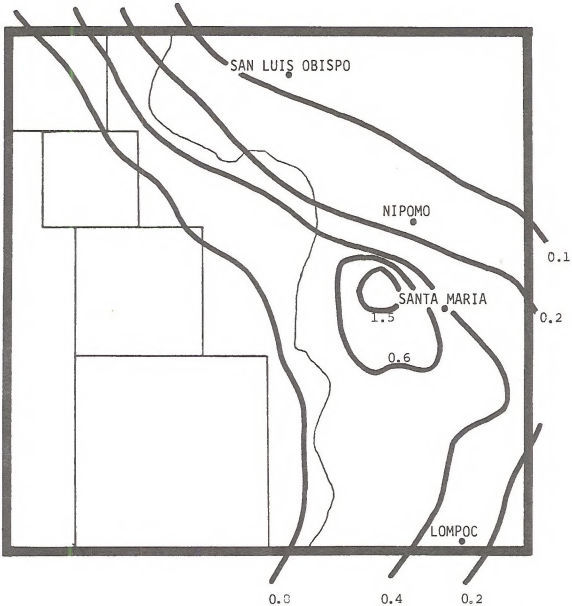
PTMTP produces hourly concentrations at up to 30 receptor points from emissions at up to 25 point sources. Inputs to the program consist of the number of sources to be considered, and for each source, the emission rate, physical stack height, stack gas temperature, volume flow (or stack gas velocity and diameter) and the source location(s) (by coordinates). The number of receptors, the coordinates of each and the height above ground of each receptor are also required. Hourly concentrations for any number of hours up to 25 can be estimated, and an average concentration over this time period calculated. For each hour, the meteorological information required is: wind direction, wind speed, stability class, mixing height, and ambient air temperature. PTMAX and PTDIS provide diagnostic information on individual stack plumes. The same stack and meteorological inputs are required.

ii. Accuracy of the Modeling

Various verification studies involving PTMTP have been reported which discuss the accuracy of the model, or adaptations of the model, in particular applications. The model is currently the subject of detailed validation studies (Bowne, 1979; Hilst, 1979). EPA has assumed that the Gaussian models are accurate to within a factor of two. This assumes that the inputs are precisely known and the modeling assumptions are met. This almost never occurs. Refer to Appendix B for additional discussion.

iii. Modeling Methodology

PTMAX and PTDIS were used to analyze offshore facility stack parameters available from other recent studies (AeroVironment, 1977; Woodward-Clyde, 1978



Isopleths
($\mu g/m^3$)

5 miles

8 kilometers

Figure VI-6. ISOPLETHS OF SO_2 FOR COMPUTED ANNUAL AVERAGES, SANTA MARIA OCS ZONE

and 1979; USGS, 1978). The objective was to choose previously studied platform stack parameters which could result in highest concentrations three miles (4.8 kilometers), or further, downwind. Ship stack parameters were also analyzed so as to anticipate highest possible concentrations onshore.

PTMAX was used to determine the distance to the concentration maximum for each stability class and wind speed (in increments of 0.5 meters per second) for all applicable sets of stack parameters. The stack parameters published in the EIR on the Shell Beta platform in San Pedro Bay (USGS, 1978) gave highest concentrations beyond three miles from a platform (the maximum concentration was computed to occur at a distance of 5.6 miles). Alternative stack data for other platforms gave highest concentrations at distances less than three miles away. Stack parameters for tugboats were used to estimate emissions characteristics applicable to supply and crew boat operations.

Two sets of meteorological parameters emerged as candidates for worst-case modeling. The Shell Beta stack parameters favored use of Pasquill stability class E and a wind speed of 4.5 mph. The tugboat stack parameters suggested use of stability class D and wind speed of 2.2 mph.

Both sets of meteorological factors were then tested using PTDIS to derive concentrations for various distances downwind. Stability class E with a wind speed of 4.5 mph gave highest concentrations at 3 miles and beyond with both types of stack parameters. An inversion layer at about 800 feet was assumed. This height is slightly above the maximum plume height calculated by PTMAX and PTDIS for Shell Beta stack parameters.

Table C-32 (Appendix C) presents stack parameters used in the Gaussian modeling. The Shell Beta data, which are used to calculate plume rise for fixed facilities offshore, represent three sets of stack parameters. In this study, nitrogen and sulfur oxide emissions are applied to each set of stack parameters in the same proportion as found in the Shell Beta Environmental Analysis (USGS, 1978). The relative apportioning of emissions is also given in Table C-32.

iv. Levels and Comparison to Standards

Concentrations from boat emissions are generally higher, for a given emission rate, than platform-related concentrations since the plume is closer to the surface. The peak concentration occurs less than 3 miles downwind of the ship.

Many modeled cases represent a mixture of platform and ship emissions. Tables VI-3 and VI-4 summarize emissions and concentrations. Emission scenarios are described in Tables C-1 through C-25 (Appendix C) and in the footnotes to Tables VI-3 and VI-4. Emissions in Tables C-1 through C-25 are tabulated for peak activities in peak emissions years. One-hour average modeling uses peak one-hour average emissions events in the tables to compute individual plumes from individual offshore facility events (for example, an OS&T and support ships in the vicinity, or a group of ships installing a platform). Modeling for TSP involves using daily-average TSP emissions to calculate a mean one hour average. Adjustments are then made for variable meteorology to compute a worst-case 24 hour average. The modeling results do not differ significantly for the various scenarios.

Table VI-3. ONE-HOUR AVERAGE MODELING EMISSIONS AND CONCENTRATIONS OF NO_2, TSP AND CO

Block	Boat Emissions (lbs/hr)			Maximum Concentrations ($\mu g/m^3$)			At Distance (km)	Character of Background Concentrations[1]		
	NO_x	TSP	CO	NO_2	TSP	CO		NO_x	TSP	CO
Eel River[2]	242	11.7	42	248	12.0	43	4.8	B	N	B
Point Arena[3]	277	11.7	42	283	12.0	43	4.8	B	A	B
Bodega [4]	195	12.0	44	200	12.3	45	4.8	B	B	B
Santa Cruz[5]	277	10.3	45	283	10.5	46	4.8	B	B	B
Santa Maria[6]	277	10.4	45	283	10.7	46	4.8	B	N-A	B

1. Key to characterization: Future one-hour background level along the coast adjacent to the Lease Sale No. 53 blocks anticipated to be: B-below; N-near; A-above air quality standards. Lowest standards are 470 g/m^3 for NO_2 and 46,000 g/m^3 for CO (Table IV-10). The worst-case modeling of TSP for a 24-hour average (state standard of 100 g/m^3) is discussed in the text. PSD limits and criteria are discussed in the text. These results apply to all scenarios.

2. Platform installation with emissions described under Section A of Tables C-2, C-4, and C-5.

3. Platform installation with emissions described in Table A-13 in Appendix A.

4. Platform installation with emissions described in Tables C-12, C-14, and C-15.

5. Platform installation with emissions described under Section A of Tables C-17, C-19, and C-20.

6. Platform installation with emissions described under Section A of Tables C-22, C-24, and C-25.

Table VI-4. ONE-HOUR AVERAGE MODELING EMISSIONS AND CONCENTRATIONS OF SO_2

Block	Platform Emissions (lbs/hr)	Boat Emissions (lbs/hr)	Maximum Concentration ($\mu g/m^3$)	At Distance (miles)[1]	Character of Background Concentration[2]
Eel River[3]	44	4	10	3	B
Point Arena[4]	30	16	11	3	B
Bodega[5]	10	2.1	3	3-5	B
Santa Cruz[6]	29	6.2	10	3-4.4	B
Santa Maria[7]	38	14	10	3	B

1. Distance ranges apply to the maximum concentration value when rounded to the tabulated value.

2. Key to characterization: Future one-hour background SO_2 level along the coast adjacent to the Lease Sale No. 53 blocks anticipated to be: B-below, N-near, A-above state air quality standard of 1,310 $\mu g/m^3$.

3. Floating production system with emissions described under Sections B and C of Table C-3 (Scenarios 1, 2, and 3).

4. OS&T with emissions described under Sections B and D of Table C-8 (Scenarios 1, 2, and 3).

5. Production platform with emissions described under Section A and C of Table C-13 (all scenarios).

6. OS&T with emissions described under Sections D and F of Table C-18 (Scenarios 1, 2, and 3).

7. Offshore gas processing plant with emissions described under Sections F, H and I of Table C-23 (Scenarios 1, 2, and 3).

Nitrogen dioxide concentrations (Table VI-3) for the peak emissions events modeled on four of the five blocks are considerable when compared to the federal one-hour average air quality standard.

These high values must be understood in the context of the modeling assumptions. The emissions levels used in the modeling are relatively short-lived. They are mobile emissions from ships, during platform installation, which are assumed to cluster in a small area while operating in an active (non-idle) mode for a major portion of one hour. One event of this type would occur for each platform or OS&T installed. It is highly improbable that the assumed worst case meteorology would occur during platform installation, because of the general infrequency of such meteorology and also because of the often unfavorable associated occurrence of poor visibility. It should also be noted that most platform installations would occur at more than 3 miles from shore.

Carbon monoxide worst case levels are insignificant when compared to the lowest one-hour standard (46,000 $\mu g/m^3$). TSP levels for a one-hour average are well below the state standard for a 24-hour average. These values, as modeled, would apply to the 24 hour average if the wind held steady in direction and speed for 24 hours. This, of course, does not occur. A computation using more realistic 24 hour meteorology would result in lower concentrations that those modeled. Sulfur dioxide levels (Table VI-4) are very low when compared to the state one-hour standard (1,310 $\mu g/m^3$).

The TSP concentrations, as calculated by assuming steady worst-case winds (Table VI-3), are less than DOI's proposed maximum allowable concentration increases for Class II Areas (37 $\mu g/m^3$; see Table VI-2). Concentrations during platform installation would be 6 $\mu g/m^3$ if worst-case winds were assumed to persist onshore for 12 hours, and less still under more realistic meteorological assumptions.

Computed worst case sulfur dioxide one-hour levels were 19 $\mu g/m^3$, or less. This level is insignificant when compared to DOI's proposed maximum allowable increase for three-hour averages (512 $\mu g/m^3$) for Class II Areas, and still small in comparison to the 24-hour limit (91 $\mu g/m^3$). Use of more realistic meteorological assumptions would drop computed levels to less than ten percent of the 24-hour limit.

TSP and SO_2 concentrations for all Lease Sale No. 53 emissions scenarios would be below the proposed DOI significance level of 5 $\mu g/m^3$ for a 24-hour average (Table VI-2) on all five OCS blocks when computed with realistic worst case meteorology (a full analysis would require detailed analysis of real meteorology and of time variation of emissions in each OCS zone). Operation of onshore gas plants (Scenario 1A) would likely require mitigation to meet applicable onshore requirements. Gas plants which have been assessed (e.g. at Los Flores Canyon) have met the equivalent EPA PSD level.

The maximum allowable increases in Class I Areas, as proposed by DOI, are slightly higher than the proposed significance levels (see Table VI-2). These limits are applicable in assessing the effects of the Santa Cruz OCS zone on the Ventana (Big Sur) designated Class I Area. The TSP and SO_2 limits would be easily met when assuming any realism to worst-case meteorology. The SO_2 eight-hour limit (8 $\mu g/m^3$) is slightly smaller than the computed one-hour average for Santa Cruz (10 $\mu g/m^3$). Clearly, variability of the wind over eight hours would reduce concentration levels to below the eight-hour limit.

Sulfur dioxide levels as computed for one-hour average worst-case meteorology (Table VI-4) are below the three-hour significance criterion (Table VI-2) of 25 $\mu g/m^3$. Computed carbon monoxide concentrations are insignificant when compared to the eight-hour and one-hour significance criteria (500 and 2,000 $\mu g/m^3$, respectively).

The impacts of any onshore gas processing plants on short-term pollutant concentrations are highly dependent on plant location and local topography and, thus, have not been modeled here. Recent air quality studies for similar type plants have indicated that with state-of-the-art pollution control devices, all air quality standards and PSD increments could be met. Under some atmospheric conditions, hydrogen sulfide levels may meet the California one-hour standard ($42\mu g/m^3$) and the Santa Barbara 3-minute standard (84 $\mu g/m^3$ and still result in odor perceptions of "rotten eggs" by some persons. This is because the California standard is set below the H_2S odor-detecting threshold of most people. (Some individuals can detect H_2S at levels as low as a few micrograms per cubic meter.) However, release of H_2S offshore (especially under Scenarios 1, 2, and 3), followed by dilution during transport is expected to result in concentrations onshore below the odor-detecting threshold.

A detailed study of short-term average concentrations from onshore gas plants has been conducted in a previous study (Woodward-Clyde, 1978). The only pollutant concentrations of concern during peak emissions years were found to be nitrogen oxides. Maximum concentrations occurred within 400 meters, or less, of the gas plants analyzed. If it were assumed that most of the nitrous oxide (NO) emissions were converted to NO_2 within this short distance, the California one-hour standard would be violated. A transport time of at least one hour, however, is necessary for oxidation of NO to NO_2 and concentrations would by then be significantly reduced. Therefore, only if an onshore plant for processing Lease Sale No. 53 gas were to be located in an area which will experience high ambient NO_2 levels would there be a possibility of exceeding a short-term average air quality standard. Concentrations near each Lease Sale No. 53 hypothesized (in Scenario 1A) gas processing plant would depend upon emissions rates for proposed plants and also upon small differences in local meteorologies. The significant factor, however, would be the ambient background level of NO_2 in each area proposed for location of a gas processing plant. There are sites available near each Lease Sale No. 53 OCS zone for which ambient NO_2 levels in the 1980's and 1990's would be sufficiently low to result in no violation of a short-average standard.

b. RAPT

Although the RAPT model is used primarily in this study for reactive modeling purposes, it can also be used to model inert pollutants. The specific features and data requirements of RAPT are described in Appendix B. Inputs include elevation of emitted pollutants and emission rates in each cell, wind speed, stability, and inversion height. A detailed description of modeling accuracy and methodology is presented in Section VI.C, Reactive Air Quality Modeling.

Table VI-5 summarizes RAPT inert modeling. Computed concentrations of SO_2 for the trajectories are tabulated. These results are also scaled for suspended particulate matter (TSP) and SO_2 concentrations from a major spill and fire. Scaling is linear in proportion to emission rates. No chemical transformations or fallout were assumed.

Table VI-5. RAPT INERT EMISSIONS AND MODELING RESULTS[1]

Trajectory	Modeling Case[2]	SO_2 Emissions (lbs/hr)	Modeled SO_2 (pphm)	Modeled SO_2 ($\mu g/m^3$)	Combustion of a Large Spill ($\mu g/m^3$)[3] SO_2	Combustion of a Large Spill ($\mu g/m^3$)[3] TSP
Bay Area #1	1	39.1	0.304	8.0	82	29
#2	1	25.3	0.164	4.3	8	3
#2	2	28.3	0.150	3.9	55	19
#2	3	25.3	0.161	4.2	66	23
#3	1	21.9	0.390	10.3	188	66
#4	1	21.9	0.031	0.8	15	5
#4	2	21.0	0.031	0.8	15	5
#5	1	21.9	0.370	9.7	177	62
#6	1	36.6	0.180	4.7	52	18
#7	1	21.9	0.077	2.0	37	13
#7	2	70.9	0.280	7.4	42	15
Scotts Valley	1	37.1	0.047	1.2	13	5
	3	37.1	0.047	1.2	13	5
	4	44.8	0.059	1.6	3	5
Salinas	1	34.1	0.040	1.1	13	5
	3	34.1	0.040	1.1	13	5
Monterey	1	34.1	0.040	1.1	13	5
	3	34.1	0.040	1.1	13	5
Nipomo	1	50.3	1.03	27.1	216	75
Santa Maria	1	57.8	2.60	68.4	474	166
Santa Ynez	1	98.8	0.46	12.1	49	17
Goleta	1	29.5	0.32	8.4	114	40
Eureka	1	74.0	3.4	89.5	492	169

1. Modeling is for one hour averages.
2. Refer to Figures IV-8 through IV-23 for the corresponding trajectories and to Appendix C, Tables C-38 through C-42 for information on inputed SO_2 emission rates. Refer also to Appendix C for details on derivation of SO_2 emission rates. SO_2 does not participate in RAPT photochemistry and, therefore, can be used to scale for other essentially inert pollutants.
3. Combustion of 1,000 barrels per day is assumed. The emission rates used in modeling are taken from the AeroVironment Report (1977), namely 400 lbs/hr for SO_2 and 140 lbs/hr for TSP. Use of emissions factors provided by Beyer and Painter (1977) would give concentrations of SO_2 reduced by 34 percent and TSP by 69 percent.

RAPT modeling results (Table VI-5) are roughly one-third to one-half of Gaussian results (Tables VI-3 and VI-4) when adjusted for differences in emissions and wind speeds. The seemingly higher RAPT results (27-90 $\mu g/m^3$ SO_2 in Table VI-5) are due to selection of trajectories which pass over multiple OCS emissions sources, and use of lower wind speeds and inversion heights (followed by fumigation onshore).

Since the results for inert pollutants (using SO_2) can be adjusted to roughly account for the relative dispersion properties of the two modeling procedures, the NO_2 results for the two modeling schemes can be compared in order to bracket the effect of the photochemical simplification in the Gaussian results. Cases from photochemical modeling result in NO_2 levels ranging up to 17 parts per hundred million (pphm) offshore and 14 pphm onshore. The state hourly standard is 25 pphm. Comparing this result to Gaussian results (Table VI-3) and adjusting concentrations for the relative effects of modeled dispersion suggests that Gaussian modeling tends to predict higher NO_2 levels by assuming complete oxidation of NO_x to NO_2.

The computations of SO_2 and TSP concentrations from a large spill and fire all assume combustion of 1,000 barrels per day. The tabulated shoreline concentrations differ by more than an order of magnitude. This large difference in results reflects the wide range in meteorological conditions which were used in the photochemical modeling. The high inert pollutant concentrations for the Eureka, Santa Maria, and Nipomo trajectories parallel the higher ozone concentrations simultaneously computed by the RAPT photochemical model. Onshore concentrations from a blowout or spill with fire could exceed levels in the air quality standards if multiple adverse factors occur simultaneously. Nevertheless, the specified levels must be exceeded twice in one year to result in violation of a federal standard. This is unlikely to occur.

C. Reactive Pollutant Modeling

1. Applicable Air Pollutants

The OCS emissions of concern for reactive modeling are hydrocarbons (HC), nitrogen oxides (NO_x), and carbon monoxide (CO). These pollutants are reactive in the presence of solar ultraviolet light. The reactive products of concern for which there is a federal AAQS are nitrogen dioxide (NO_2) and photochemical oxidants (O_x). The principal and most familiar chemical species of the latter is ozone (O_3),

The relative proportion of each reactive product in an air parcel is hard to predict prior to modeling. Reactions in the atmosphere involve scores of organic (HC) species. Reaction products depend on the many HC concentrations and the concentrations of the NO_x species, NO_2 and nitric oxide (NO), as well as on the solar intensity at the time. The RAPT and IMPACT models convert the many HC species, in terms of reactivity, to three equivalent HC species; see Appendix B for details.

Some general properties of photochemical reactions help in understanding the results from the modeling cases which follow. First, during the night when photodissociation (splitting of certain molecules by ultraviolet light) ceases, the most reactive species react and decrease in concentrations. Specifically, ozone concentrations decrease. This process is enhanced if the air parcel should pass over Lease Sale No. 53 sources of nitric oxide emissions; the NO

would be converted to NO_2 with a reduction of O_3 to ordinary oxygen. Second, if air parcels pass over OCS emission sources during daylight hours there would be a similar scavenging by NO of O_3 to a level lower than would otherwise prevail (the baseline level). Time and solar ultraviolet radiation would then be necessary for NO_2 generation, for the NO_2 levels to decrease, and then for the O_3 level to return to the baseline concentration and, perhaps, finally to exceed it.

Another factor specific to petroleum sources contributes to the slowness of attaining O_3 impact levels. Crude oil emissions are relatively non-reactive (90 percent of reactive hydrocarbons were lumped as HC2, the least reactive hydrocarbon species in the LIRAQ-2 photochemistry; see Appendix B). Petroleum hydrocarbons must be chemically transformed before they can result in enhanced O_3 production. If sufficient time or solar ultraviolet is not available, the baseline O_3 concentration will not be exceeded, or sometimes not even be reached. Therefore, ozone impacts are sensitive to the timing of those air parcels which would pass over OCS Sale No. 53 emission sources and continue to populated areas of concern.

The modeling is centered on one-hour averages for two reasons: (1) the data from monitoring stations are averaged hourly and (2) the ozone air quality standards are expressed in terms of hourly averages (Table IV-3).

2. Model Selection

The RAPT (Reactive Air Pollutant Transport) model was selected for most cases of Lease Sale No. 53 modeling. The RAPT model represents a cross-wind wall of cells which moves downwind with a flow of reacting emissions in ambient air. The model provides detailed resolution of a reacting plume of emissions and can also be used for evaluating changes in air quality across a region. For either use, the RAPT model offers cost effective calculations which maintain the significant physical and chemical processes for simulating ozone production from plume and relatively uniform area emission sources. Appendix B describes the RAPT model in detail. The appendix also briefly describes the IMPACT model which was used for modeling one case in the San Francisco area (see Section VI.C.6.d).

3. Modeling Assumptions and Methodology

Assumptions and methodology used in simulation models are generally described in Appendix B. RAPT is a point source Lagrangian model with some regional capabilities. The model sweeps through the region by following a previously determined trajectory. Emissions swept up each hour must be predetermined.

4. Data Requirements

For a given impact simulation, the model is run three times: a verification run for comparison with observed oxidants, a projection of this baseline to a future year, and a run with OCS emissions. The required data for each case are: (1) initial pollutant concentrations (reactive hydrocarbons [RHC], nitrogen oxides, carbon monoxide, and ozone); (2) other varying emissions of RHC and NO_x encountered as the Lagrangian grid of cells moves along the trajectory;

(3) time-varying insolation (sunlight); and (4) time-varying wind speed, atmospheric stability, and inversion height.

5. Accuracy of the Modeling

RAPT uses finite difference algorithms to compute diffusion between cells. Resolution is to within a few cells. Since central cells have a cross-wind dimension of as little as 100 meters, resolution varies from a fraction of a kilometer near the plume center to about a kilometer on the edges of the grid (width of the grid was set to 5 kilometers edge-to-edge for this study).

Temporal resolution is on the order of one to two hours. Experience has shown that modeling results are relatively insensitive to the specific chemical equations and reaction rates used in the chemical kinetics submodule of a photochemical model (e.g. EPA, 1977). The mechanism used is LIRAQ-2 (Table B-1 in Appendix B), an updated LIRAQ chemistry developed by the Lawrence Livermore Laboratory.

Accuracy of the results depends upon the care taken in the modeling effort. Accuracy to within better than a factor of two is possible. The algorithms and submodules of which RAPT has been constructed have been individually tested for several years.

To minimize errors, RAPT is first verified against air quality monitoring data. Figure VI-7 is a scatter plot of observed versus calculated oxidants (O_3 and NO_2) for baselines, along selected trajectories, used in this study. Initial modeled air quality is then projected forward to an anticipated year for proposed maximum Lease Sale No. 53 activity. This introduces some error in estimating a future baseline. Modeling results are emphasized as increments in oxidant levels relative to the baseline. Increments have smaller second-order errors than absolute ozone values. (Figures C-5 through C-35, in Appendix C, present modeling inputs for baseline simulations. Figures D-1 through D-29, in Appendix D, display the time evolution of nitrogen dioxide and ozone concentrations for current and future year baseline simulations.)

It must be stressed that future OCS events can only be roughly estimated. Errors in the estimated scenarios, levels of activity, and emission factors propogate through into the estimates of ozone levels and increments. Meteorological factors could be less or more severe in the actual years which will see maximum Lease Sale No. 53 activities. Impact results cannot be stated with precision.

Emphasis in each subsection of the study has been placed on realistic worst-case assumptions. This procedure greatly reduces the probability that the computed ozone levels underpredict. By also keeping assumptions realistic, there is a reduced probability that estimates greatly overpredict impacts.

6. Levels and Comparison to Standards

This section presents the results of the reactive pollutant modeling for each Lease Sale No. 53 block. A number of OCS emissions scenarios are simulated. These are designed to represent the year and circumstances which would result in maximal one-hour average hydrocarbon emissions. General emissions ranges are described in Section V.D. Maximal one-hour average hydrocarbon and nitrogen

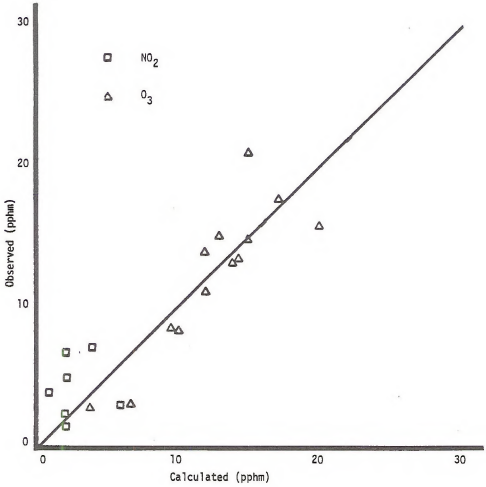


Figure VI-7. OCS BASELINE CALIBRATION OF OBSERVED VERSUS CALCULATED RAPT VALUES

oxide emissions are tabulated in Tables C-1, C-6, C-11, ..., and C-21 (Appendix C) by emissions sources for the five Lease Sale No. 53 blocks. Emissions inputs for the actual simulations are described in Tables C-38 through C-42 (Appendix C). For each scenario, the emitting facilities are distributed in space and time in a reasonable but worst-case spread. For example, all calculations assume one OS&T along the centerline of the trajectory. These emissions scenarios can be described in terms of the number of emitting facilities placed along the trajectory centerline and off centerline. Emissions from supply and crew boats are apportioned along the trajectory by facility.

Both normal operations and accident scenarios are assessed by the reactive modeling. Most ozone increments are less than 0.01 ppm of ozone. Numerous simulations were made. Those reported herein represent typical and worst cases. Some modeling assessments were not performed when similar cases which were already run clearly indicated ozone increments would be less than 0.01 ppm. Results are summarized in Table VI-6 and Figure VI-8. In general, higher incremental ozone was computed for cases involving lower baseline ozone or large accidental emmissions. The simultaneous inert modeling using RAPT shows that higher increments for cases with low baseline ozone follow principally from choices of meteorological and air quality inputs which are highly uneven from block to block. Refer to Section VI.B for a discussion of RAPT inert modeling and to Section IV.A.4 for a discussion of the trajectories.

Some of the future baselines used in determining incremental ozone from possible peak year Lease Sale No. 53 activities are above state or national ozone standards. One modeling case represents a baseline just below the state standard for oxidants (10 pphm), with the level resulting from modeled OCS emissions barely exceeding the standard. There were two similar cases relative to the national standard (12 pphm). There were a total of 18 cases modeled based on peak year emissions resulting from normal operations on the OCS.

The number of cases analyzed and the range in meteorology assessed were constrained principally by shortcomings in knowledge of pertinent meteorology and ambient air quality offshore. Limitations in state-of-the-art air quality models must also be recognized. This relatively brief modeling analysis, the theoretical nature of the modeling emissions and the paucity of specific monitoring data for ozone directly downwind of existing OCS activities preclude a definitive conclusion on whether an ozone standard would be exceeded by Lease Sale No. 53 activities. The modeling results do point to a concern over effects of unmitigated OCS emissions in areas which may be marginally in attainment of the ozone standard in future years.

A full discussion of results is contained in the following subsections. Reference should be made to the trajectories in Section IV.A.4.

a. Eel River

This first trajectory simulates impact near Eureka. In the absence of actual O_3 measurements, the present simulation with assumed conditions leads to 0.06 ppm of ozone. Future changes in non-OCS hydrocarbon emissions are assumed to be insignificant. Thus, 0.06 ppm of ozone (O_3) is also the 1987 baseline against which the OCS emissions are assessed. The time evolutions of O_3 and NO_2 along this trajectory are shown in Figures VI-9 through VI-12 for the baseline as well as for emissions scenarios involving routine operations,

Table VI-6. SUMMARY OF OZONE IMPACT RESULTS[1]

OCS Block	Trajectory	Ozone Baselines (pphm)			Ozone Increments (pphm) Relative to Future Baseline From[2]			
					Normal Operations		Accidents	
		Observed Measurement	Simulated Present	Future Baseline	At Observation Point	Maximum Onshore	At Observation Point	Maximum Onshore
Eel River	Eureka	--	6	6	--	3	--	8-15
Point Arena	Ft. Bragg	--	7	7	--	3	--	0-12
Bodega	Bay Area 3	9	10	9	1	1	1-2	1-2
	Bay Area 4	10	9	11	0	2	2	2
	Bay Area 5	13	12	12	1	1	(-1)-1	0-1
	Bay Area 7	8	9	9	1	1	0	0
Santa Cruz	Bay Area 1	15	15	14	0	0	1-4	3-7
	Bay Area 2	14	12	11	0	1	--	--
	Bay Area 6	20	19	20	0	0	1	1
	Salinas	3	4	4	0	0	1	1
	Monterey	--	4	3	--	0	--	(-2)-0
	Scotts Valley	21	15	15	0	0	-1	-1
Santa Maria	Nipomo	14	13	16	0	2	0-4	0-6
	Santa Maria	12	12	11	0-1	0-1	3	3
	Santa Ynez	13	13	11	2	2	2-3	2-3
	Goleta	3	7	6	1	1	4-5	4-5

1. California state, and national, one-hour standards are 10 pphm and 12 pphm, respectively. The computer runs modeled various high emission scenarios. Refer to Tables C-38 through C-42 for a description of scenarios applicable to each modeling case. In general, tanker emissions at OS&Ts for Scenarios 1, 2, and 3 were stressed, since highest one-hour average hydrocarbon emissions are produced during tanker or barge loading.

2. Cases were run using normal worst hour emissions rates, and others involving spills or blowouts. Accident cases have very low probability of occurring. The modeling further assumes concurrent worst case meteorology.

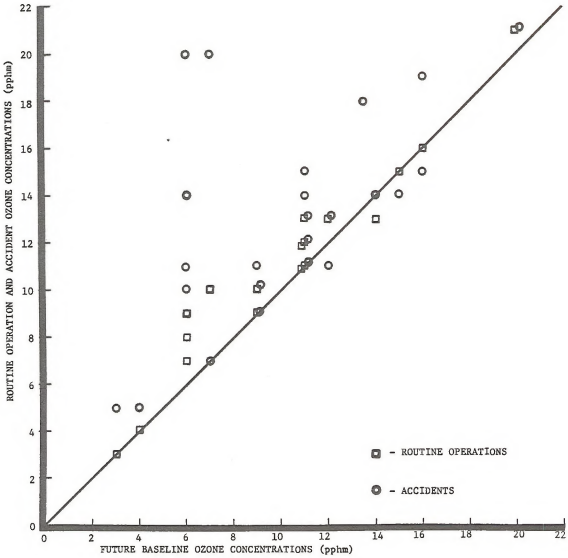
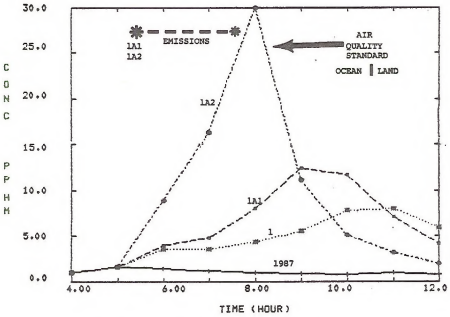
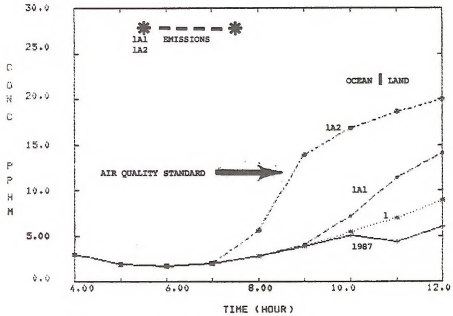


Figure VI-8. OCS OZONE EMISSION IMPACT COMPARISON



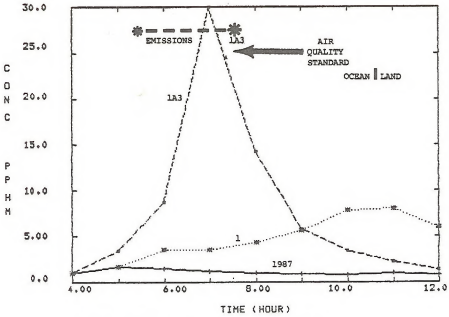
(See Figure IV-7 for Trajectory)

Figure VI-9. NO_2 FOR CASES 1, 1A1, AND 1A2 OF THE EUREKA TRAJECTORY



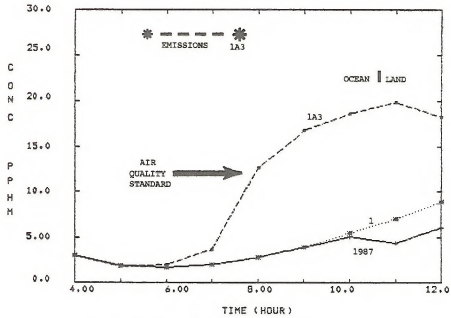
(See Figure IV-7 for Trajectory)

Figure VI-10. O_3 FOR CASES 1, 1A1, AND 1A2 OF THE EUREKA TRAJECTORY



(See Figure IV-7 for Trajectory)

Figure VI-11. NO_2 FOR CASES 1 AND 1A3 OF THE EUREKA TRAJECTORY



(See Figure IV-7 for Trajectory)

Figure VI-12. O_3 FOR CASES 1 AND 1A3 OF THE EUREKA TRAJECTORY

and for three accident emissions scenarios. On these graphs, the emissions timing, land-fall of the trajectory and the air quality standards are also plotted for reference.

The routine operations case (Case 1) is for emissions Scenarios 1, 2, and 3 for the peak year 1987 (see Section V.D.2.a). It involves a production platform, mobile emissions, another production system and supply activities apportioned during the hours of 0500 to 0700 PST along the trajectory centerline. The three accident scenarios (1A1, 1A2 and 1A3) add to Case 1 the emissions of a small (10^6 ft^3/day) and large (10^7 ft^3/day) blowout at 0500 PST and 0700 PST, respectively. The calculated concentration in Case 1 shows about 3 pphm O_3 (equivalent to 0.03 ppm) above the baseline value for a total of 8.9 pphm onshore as resulting from routine operations. The large accidents produce up to a total of 20 pphm of O_3 onshore, and 30 pphm of NO_2 offshore and about 10 pphm of NO_2 onshore. These ozone and nitrogen dioxide levels are above standards (Table III-1). The national ozone standard is 12 pphm. The state ozone standard is 10 pphm, and the state NO_2 standard is 25 pphm. The high NO_2 calculated here results from the extremely low wind speeds used in the modeling (2 to 6 miles per hour) which permitted high NO concentrations. These were hypothetical winds chosen for worst-case analysis. In the accident scenarios, the large quantity of added hydrocarbons contributed to rapid conversion of emitted NO to NO_2. The large accidental spill would have a very low probability of occurring, especially with concurrent worst-case meteorology.

b. Point Arena

The trajectory for this block simulates impact near Fort Bragg. Again, due to lack of ozone data and relevant case studies, the present simulation is hypothetical and leads to a baseline of 7.1 pphm ozone (O_3). Future changes in non-OCS hydrocarbon emissions are assumed to be insignificant. Thus, 7.1 pphm O_3 is also the 1989 baseline against which the OCS emissions are assessed. The time evolutions of O_3 and NO_2 along this trajectory are shown in Figures VI-13 and VI-14 for the baseline, for cases involving routine operations, and two accident scenarios.

The routine operation case (Case 1) represents emissions Scenarios 1 and 2 for the peak hydrocarbon emissions year 1989 (see Section V.D.2.b). It assumes an OS&T, a platform, tanker loading, a floating production facility and supply and crew transport activity apportioned during 0000 through 0700 PST along the trajectory centerline. The two accident scenarios (1A2 and 1A4) involve centerline spills of 140 barrels (or blowout of 1,000 barrels/day) at 0100 and 0700, respectively. The calculated concentrations show about 3 pphm O_3 added (for a total of 10.3 pphm) onshore for the routine operations case. The accidents produce ozone levels of 17.8 to 19.5 pphm O_3 onshore. These levels, due to accidents, are over national and state ozone air quality standards. A major accident, concurrent with such extreme meteorology, would have a very low probability of occurring.

c. Bodega

Four trajectories were used to analyze possible impacts from the Bodega OCS block emissions. These trajectories are designated as Bay Area trajectory numbers 3, 4, 5, and 7.

Bay Area trajectory No. 3 simulates a day with observed ozone of 9 pphm. Simulated ozone is 9.8 pphm for present conditions and 8.9 pphm O_3 from planned HC and NO_x reductions in 1987. Case 1 corresponds to Transportation Scenarios 1, 1A and 2 with an OS&T, barge loading and supply and crew transit on centerline and a platform with boats off centerline. Emissions are apportioned during the hours of 0200 through 0600 PST. The two accidents (1A1 and 1A3) are a large spill (1,000 barrel) and a small spill (140 barrel) or, equivalently, a 1,000 barrel/day blowout. The large spill is assumed to occur at 0200 PST and the smaller spill at 0400 PST. The evolution of O_3 and NO_2 are plotted in Figures VI-15 and VI-16. Case 1 simulates ozone increasing to 9.6 pphm while the accidents result in 10 and 10.7 pphm O_3, respectively.

Bay Area trajectory No. 4 has observed O_3 of 10 pphm. Simulated ozone is 9.3 pphm for present conditions and 10.7 pphm O_3 from planned HC and NO_x reductions in 1987. The routine operations of Case 1 correspond to Transportation Scenarios 1, 1A and 2. Case 1 assumes an OS&T and platform on centerline with emissions apportioned during 0200-0300 PST. An accidental blowout (1,000 barrels/day) and fire was also simulated (Case 1A1). The O_3 and NO_2 results are shown in Figures VI-17 and VI-18. The simulated ozone increment from routine operations is small (0.3 pphm). The accident emissions, however, produce O_3 levels just over the federal standard of 12 pphm.

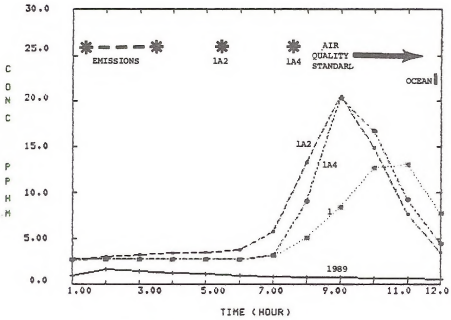
Bay Area trajectory No. 5 describes a day with observed O_3 of 13 pphm. Simulated ozone is 11.0 pphm for present conditions and 12.3 pphm O_3 assuming planned HC and NO_x reductions in 1987. Routine operations(Case 1) correspond to Transportation Scenarios 1, 1A and 2 and assume an OS&T platform and supply and crew transport on centerline. The results, as depicted in Figures VI-19 and VI-20, show small ozone increments (about 1 pphm O_3) over levels which were in excess of the ozone standards.

Bay Area trajectory No. 7 describes a day with observed O_3 of 8 pphm. Simulated ozone is 8.6 pphm for present conditions and 8.5 pphm O_3 from planned HC and NO_x reduction in 1987. Routine operations correspond to emissions scenarios 1, 1A and 2 and further assume an OS&T, a platform and supply and crew transport on centerline. The results, as shown in Figures VI-21 and VI-22, involve small ozone increments (less than 1 pphm O_3) relative to levels below standards.

d. Santa Cruz

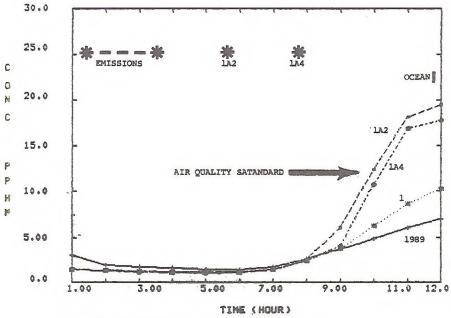
Six trajectories are used to simulate ozone which could result from the Santa Cruz OCS block emissions. These trajectories are designated as Bay Area trajectories numbers 1, 2 and 6. Other trajectories terminate at Scott's Valley, Monterey and Salinas, respectively, in the North Central Coast Air Basin (Figure III-3).

Bay Area trajectory No. 1 describes a day with observed O_3 of 15 pphm. Simulated ozone is 15.3 pphm for present conditions and 13.6 pphm for projected conditions from planned HC and NO_x reduction in 1990. Case 1 corresponds to Scenario 1 and assumes an OS&T, drilling platform, and supply and crew transport on centerline. Pipeline construction was assumed off centerline. Emissions are apportioned during 0300 - 0500 PST. The two accident scenarios (2A1, 2A2) represent a small spill (140 barrels) or blowout (1,000 barrels/day) and a large spill (10,000 barrels). Accidental emissions are introduced into Case 2 which includes emissions from tanker loading on centerline. The evolution of



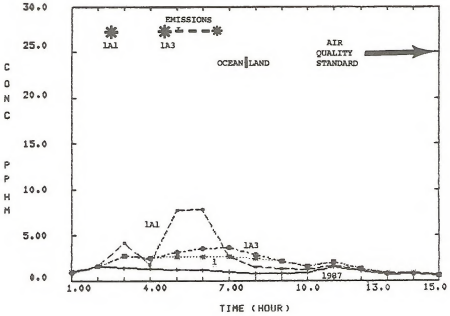
(See Figure IV-8 for Trajectory)

Figure VI-13. NO_2 FOR CASES OF THE FORT BRAGG TRAJECTORY



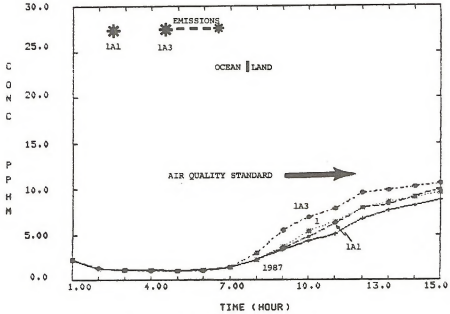
(See Figure IV-8 for Trajectory)

Figure VI-14. O_3 FOR CASES OF THE FORT BRAGG TRAJECTORY



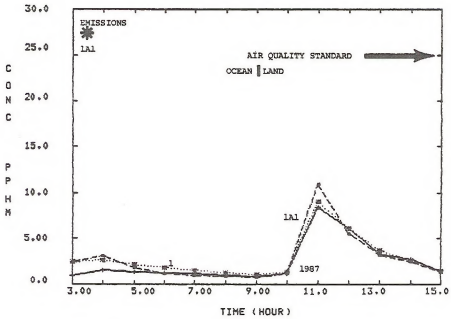
(See Figure IV-9 for Trajectory)

Figure VI-15. NO_2 FOR CASES OF THE BAY AREA #3 TRAJECTORY



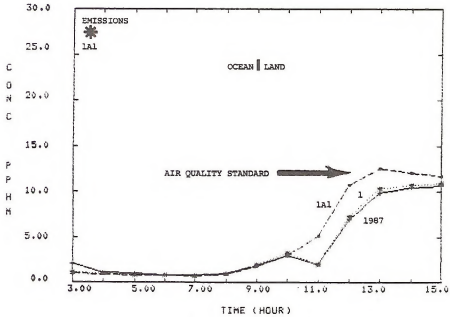
(See Figure IV-9 for Trajectory)

Figure VI-16. O_3 FOR CASES OF THE BAY AREA #3 TRAJECTORY



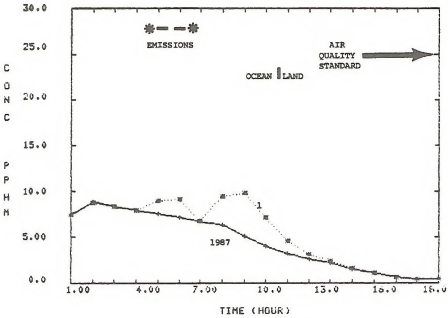
(See Figure IV-11 for Trajectory)

Figure VI-17. NO_2 FOR CASES OF THE BAY AREA #4 TRAJECTORY



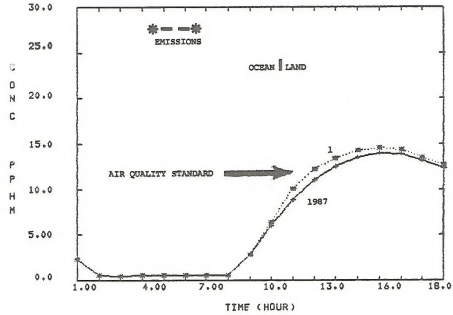
(See Figure IV-11 for Trajectory)

Figure VI-18. O_3 FOR CASES OF THE BAY AREA #4 TRAJECTORY



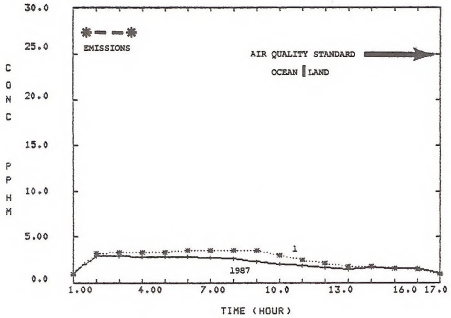
(See Figure IV-10 for Trajectory)

Figure VI-19. NO_2 FOR CASES OF THE BAY AREA #5 TRAJECTORY



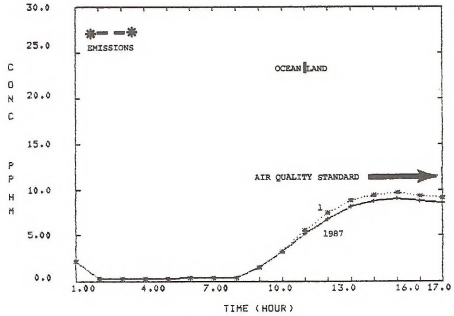
(See Figure IV-10 for Trajectory)

Figure VI-20. O_3 FOR CASES OF THE BAY AREA #5 TRAJECTORY



(See Figure IV-12 for Trajectory)

Figure VI-21. NO_2 FOR CASES OF THE BAY AREA #7 TRAJECTORY



(See Figure IV-12 for Trajectory)

Figure VI-22. O_3 FOR CASES OF THE BAY AREA #7 TRAJECTORY

O_3 and NO_2 concentrations are plotted in Figures VI-23 and VI-24. Case 1 results in a small increment (less than 1 pphm) of ozone, while the accidents add 2 and 5 pphm of O_3, respectively to ozone levels over standards.

Bay Area trajectory No. 2 describes a day with observed ozone of 14 pphm. Simulated ozone is 12.2 pphm for present conditions and 11.4 pphm from planned HC and NO_x reductions in 1990. Case 1 corresponds to Scenario 1 and assumes an OS&T, a production platform and transport on centerline and a floating platform off centerline. Emissions are apportioned during 0400 - 0600 PST.

The evolution of O_3 and NO_2 concentrations is shown in Figure IV-25 and VI-26. Case 1 results in an ozone increment less than 1 pphm to a baseline ozone level near the national ozone standard.

Bay Area trajectory No. 6 describes a day with observed ozone of 20 pphm. Simulated ozone is 19.0 pphm for present conditions and 20.4 pphm O_3 with planned HC and NO_x reductions in 1990. Case 1 corresponds to Scenario 3 and assumes an OS&T, tanker loading, a production platform and a drilling platform on centerline, with a floating platform off centerline. Emissions are apportioned during 0000-0200 PST.

The evolution of O_3 and NO_2 concentrations is plotted in Figures VI-27 and VI-28. Case 1 results in ozone increments of less than 1 pphm to baseline ozone which is modeled as above the standard.

The Scotts Valley trajectory describes a day with observed O_3 of 21 pphm. Simulated ozone is 15.0 pphm for present conditions at the end of the trajectory, with the peak level of 18 pphm occurring along the trajectory. The 1990 baseline is 14.5 pphm O_3. Case 1 corresponds to Scenario 1 with an OS&T, a production platform, a platform with drilling and a floating platform on centerline. An OS&T and a drilling platform are assumed off centerline. Emissions are apportioned during 0300 - 0800 PST. The evolutions of O_3 and NO_2 are shown in Figure VI-29 and VI-30. Case 1 ozone increments are small (less than 0.5 pphm).

The Monterey and Salinas trajectories are very similar. Onshore emissions do differ somewhat, as is evident in the data plots of Figures VI-31 through VI-34. Observed O_3 is 3 pphm at Salinas with 4.4 and 3.8 pphm simulated for present conditions at Salinas and Monterey, respectively. The corresponding 1990 baseline levels are 3.8 and 3.3 pphm, respectively. Case 1 corresponds to Transportation Scenario 1 and assumes an OS&T, two production platforms and a floating platform on centerline. Two drilling platforms are assumed off the centerline. Emissions are apportioned during 0500 - 0600 PST. An accident scenario with a small spill is also plotted in Figures VI-33 and VI-34. The resulting ozone increments are small, and even negative.

The three-dimensional grid model IMPACT (Integrated Model of Plumes and Atmospherics in Complex Terrain) was also used to simulate the potential impacts of OCS activities. Bay Area Trajectory No. 6 (Figure IV-14) was chosen for IMPACT simulation. IMPACT is briefly described in Appendix B (Subsection B-3).

A 16-hour simulation was carried out for a source located near the middle of the Santa Cruz OCS zone. The source was assumed to emit continuously at a rate of 100 grams per second (g/sec). The IMPACT simulation resulted in insignificant onshore concentrations; specifically, the highest concentration at San Francisco was less than 0.05 pphm after six hours of transport, and the

highest concentration reaching the South Bay was less than 0.01 pphm after twelve hours of transport. Based on these results, further simulation by IMPACT was not warranted. The worst case emissions scenario (an accident with 220 g/sec of RHC and 25 g/sec of NO) would result in concentration increments of less than 1 pphm (this level is the effective measurement threshold). In a simulation comparable to a RAPT case, the concentrations from an IMPACT run would be lower by several orders of magnitude. Refer to Appendix B (subsection B.3) for a discussion of the concentration differences between RAPT and IMPACT.

e. Santa Maria

The analysis of ozone production from possible Santa Maria OCS block emissions are analyzed using four trajectories which terminate at Nipomo, Santa Maria, Santa Ynez and Goleta.

The Nipomo trajectory describes a day with observed ozone of 14 pphm. Simulated ozone is 13.3 pphm for present conditions and 15.5 pphm for assumed ambient air quality and emissions conditions in 1991. Case 1 corresponds to emissions Scenario 1 and assumes an OS&T and a production platform on centerline. Production and drilling platforms are assumed off centerline, together with supply and crew transport activity. Emissions are apportioned during 0400 - 1000 PST. The evolution of O_3 and NO_2 concentrations are shown in Figures VI-35 and VI-36. Maximum ozone levels occur at land-fall and result in ozone increments of 2.5 pphm for normal operations and 7 pphm for a small spill (Case 1A2) to ozone levels above standards.

The Santa Maria trajectory describes a day with observed ozone of 12 pphm. Simulated ozone is 12.9 pphm for present conditions and 10.9 pphm for conditions projected to 1991. Case 1 corresponds to emissions Scenario 1 and assumes an OS&T and two production platforms on centerline. Two production platforms are assumed off centerline. Emissions are apportioned during 0100 - 0800 PST and include crew and supply transport emissions. The evolution of O_3 and NO_2 concentrations are shown in Figures VI-37 and VI-38 . The ozone increment is slightly negative.

The Santa Ynez trajectory describes a day with observed ozone of 13 pphm. Simulated ozone is 13.1 pphm for present conditions and 11.4 pphm for baseline conditions. Case 1 corresponds to Transportation Scenario 1 and assumes an OS&T, a production platform and an offshore gas plant on centerline. Four production platforms, a drilling platform and pipeline construction are assumed off centerline. Emissions are apportioned during 2100 - 0600 PST. Three accidents are analyzed (Cases 1A1, 1A2, 1A3). They involve a large (10,000 barrel spill)(Case 1A), a small (140 barrel) spill or blowout (1,000 barrels/day) (Case 1A2), and a blowout with fire (Case 1A3).

The evolution of O_3 and NO_2 concentrations are shown in Figures VI-39 through VI-42. For normal operations, ozone increments vary between 1.5 and 2 pphm onshore relative to ozone levels which are near the standards. Increments increase to as much as 3 pphm for the large spill.

The Goleta trajectory describes a day with observed O_3 of 3 pphm. Assumed initial conditions resulted in simulated ozone of 6.9 pphm for present conditions. The level dropped to 5.8 pphm when projected to Santa Barbara Channel and onshore emissions conditions assumed for 1991. Case 1 corresponds to Scenario 1 and assumes an OS&T, four production and one drilling platform and

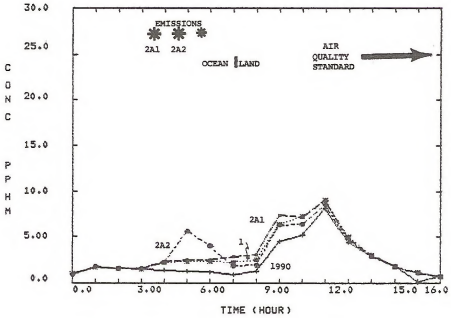
an offshore gas processing plant on centerline. Three platforms and 2 pipeline construction sites are assumed off centerline. Emissions also result from supply and crew transport activities. Accident emissions scenarios are run for a large (10,000 barrels) spill (Case 1A1) and a small spill (140 barrels) or blowout (1,000 barrels/day) (Case 1A2). The evolution of O_3 and NO_2 concentrations are shown in Figures VI-43 and VI-44. Normal operations (Case 1) result in an increment of 1 pphm O_3. The accident scenarios result in ozone increments of 3 to 4 pphm. For the observed ozone (3 pphm), the additional ozone results in a total level below standards. The total level approaches standards when the simulated baseline value is considered.

The Goleta trajectory modeling results also provide information on the cumulative effects of OCS Lease Sales Nos. 35, 48 and 53. OCS Lease Sale No. 35 emissions are incorporated in the 1976 baseline calculation between the hours 3200 through 3800 (i.e. 8 a.m. through 2 p.m. of the second day) when the trajectory passes over Sale No. 35 lease tracts (refer to Figure IV-20 for the Goleta trajectory and Figures D-27 and D-28 in Appendix D for 1976 and 1991 baselines for NO_2 and O_3). Lease Sale No. 48 OCS emissions are similarly included in the 1991 baseline calculation. Tables C-26 through C-30 in Appendix C summarize 1976 and 1991 baseline inputs and give their locations in the Santa Barbara Channel.

A reduction in ozone levels is projected to occur as the trajectory passes over the Santa Maria zone (Figure D-28) in the 1991 baseline modeling case because of an anticipated reduction of hydrocarbon emissions in the South Central Coast Air Basin. As the trajectory passes over the Santa Barbara Channel, the ozone level is also lower than in the 1976 baseline case because of increased nitric oxide OCS emissions which "scavenge" O_3, and because of insufficient time for hydrocarbon emissions to dilute and react. A trajectory which passes over the Santa Barbara Channel earlier in the day and extends beyond Goleta could result in a rise and then a decline of NO_2, followed by an increase in ozone downwind of Santa Barbara.

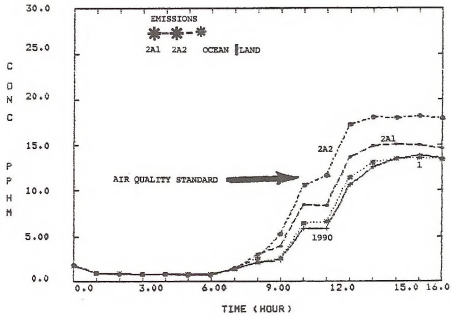
The inclusion of Lease Sale No. 53 emissions in the computation results in a small (about 0.01 ppm) increase in ozone after sunrise as the trajectory passes over Point Conception (Figure VI-44); this is because emissions injected at night have sufficient time to dilute by morning to result in ozone formation. However, the net modeled ozone as the trajectory passes over the Santa Barbara Channel with all OCS emissions in 1991 is essentially unchanged relative to the modeled level for 1976.

If Lease Sale No. 68 emissions were to result in additional OCS development activity in the western end of the Channel by 1991, the ozone level could decrease relative to 1976 because of NO "scavenging." Although the Goleta trajectory modeling results do not indicate potential cumulative impacts resulting from OCS Lease Sale Nos. 35, 48 and 53 emissions, it can not be ruled out that, under certain circumstances, OCS emissions from the Santa Maria and Santa Barbara Channel tracts could combine to provide higher ozone increments somewhere in southern California. A discussion of combined OCS block ozone impacts can be found in "Outer Continental Shelf Drilling and Associated Activities: Analysis of Air Quality and Land Use Impacts on San Diego County" (Environmental Resources Group, 1979).



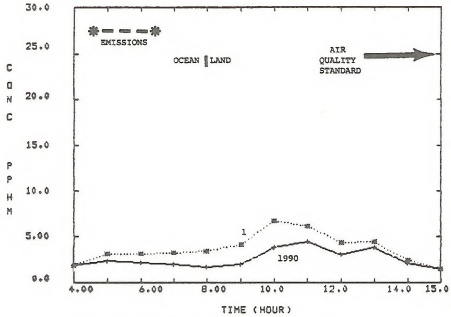
(See Figure IV-13 for Trajectory)

Figure VI-23. NO_2 FOR CASES OF THE BAY AREA #1 TRAJECTORY



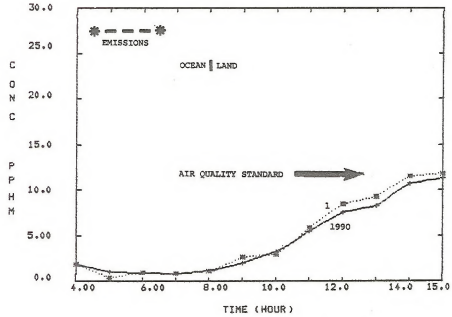
(See Figure IV-13 for Trajectory)

Figure VI-24. O_3 FOR CASES OF THE BAY AREA #1 TRAJECTORY



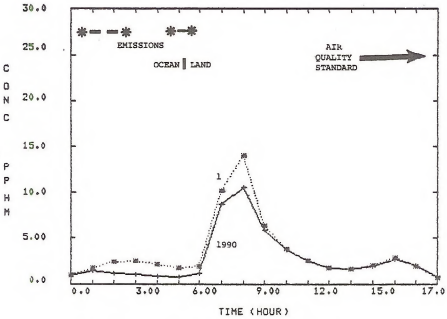
(See Figure IV-15 for Trajectory)

Figure VI-25. NO_2 FOR THE CASES OF THE BAY AREA #2 TRAJECTORY



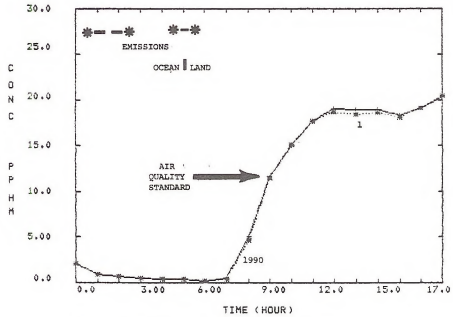
(See Figure IV-15 for Trajectory)

Figure VI-26. O_3 FOR CASES OF THE BAY AREA #2 TRAJECTORY



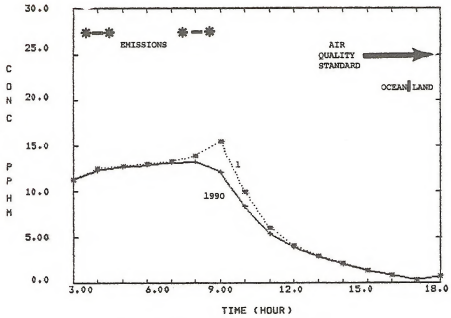
(See Figure IV-14 for Trajectory)

Figure VI-27. NO_2 FOR CASES OF THE BAY AREA #6 TRAJECTORY



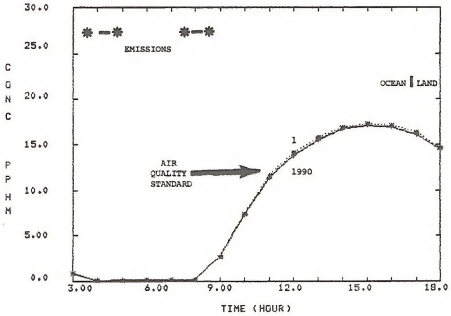
(See Figure IV-14 for Trajectory)

Figure VI-28. O_3 FOR CASES OF THE BAY AREA #6 TRAJECTORY



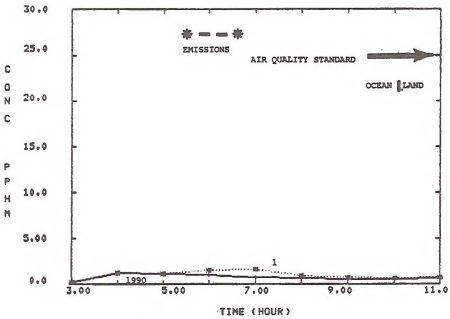
(See Figure IV-17 for Trajectory)

Figure VI-29. NO_2 FOR CASES OF THE SCOTTS VALLEY TRAJECTORY



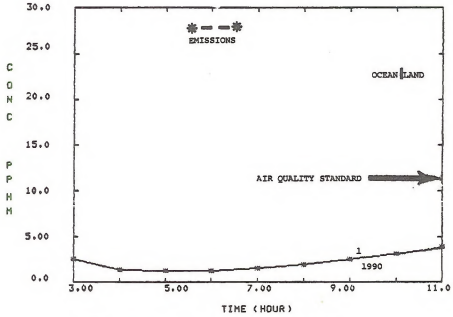
(See Figure IV-17 for Trajectory)

Figure VI-30. O_3 FOR CASES OF THE SCOTTS VALLEY TRAJECTORY



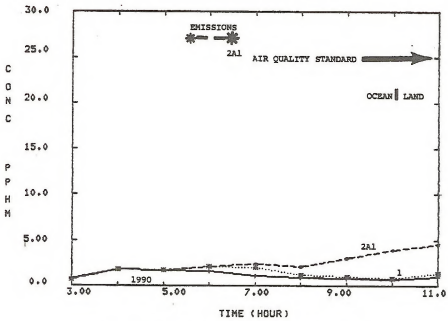
(See Figure IV-16 for Trajectory)

Figure VI-31. NO_2 FOR CASES OF THE SALINAS TRAJECTORY



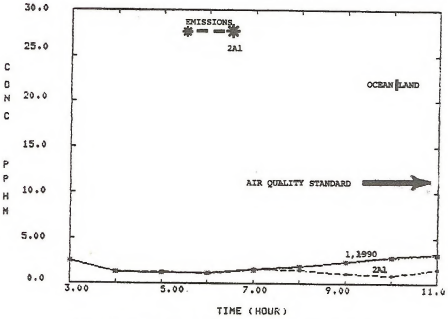
(See Figure IV-16 for Trajectory)

Figure VI-32. O_3 FOR CASES OF THE SALINAS TRAJECTORY



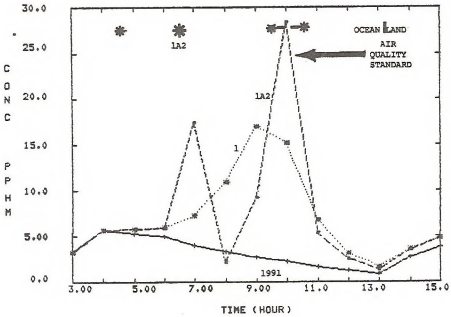
(See Figure IV-16 and Section VI.C.6.d)

Figure VI-33. NO_2 FOR CASES OF THE MONTEREY TRAJECTORY



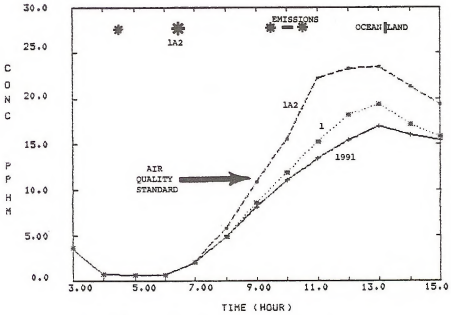
(See Figure IV-16 and Section VI.C.6.d)

Figure VI-34. O_3 FOR CASES OF THE MONTEREY TRAJECTORY



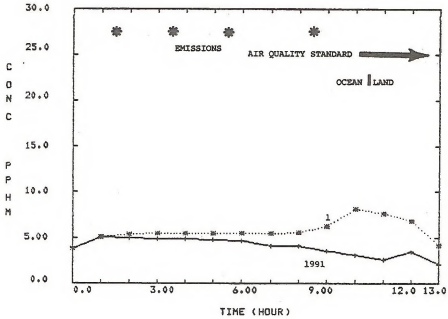
(See Figure IV-18 for Trajectory)

Figure VI-35. NO_2 FOR CASES OF THE NIPOMO TRAJECTORY



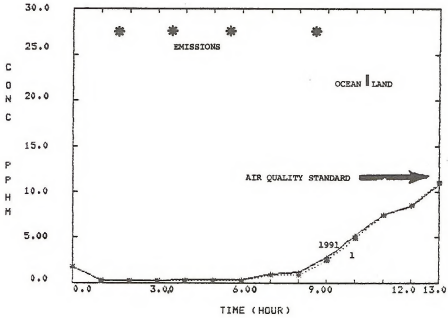
(See Figure IV-18 for Trajectory)

Figure VI-36. O_3 FOR CASES OF THE NIPOMO TRAJECTORY



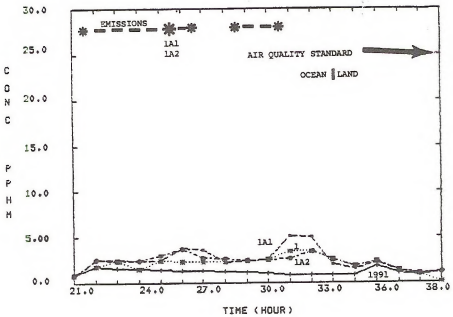
(See Figure IV-22 for Trajectory)

Figure VI-37. NO_2 FOR CASES OF THE SANTA MARIA TRAJECTORY



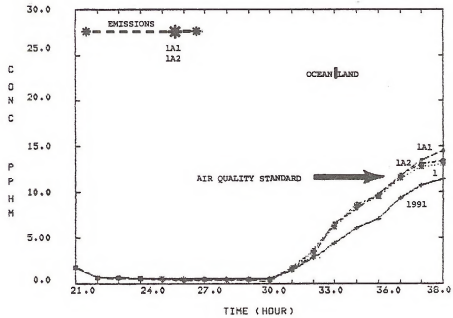
(See Figure IV-22 for Trajectory)

Figure VI-38. O_3 FOR CASES OF THE SANTA MARIA TRAJECTORY



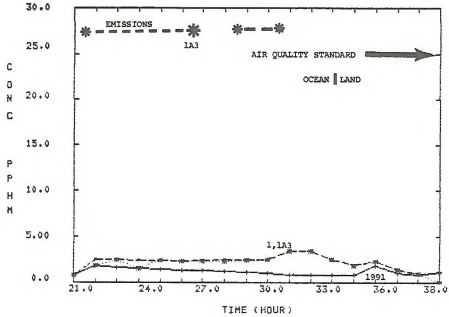
(See Figure IV-21 for Trajectory)

Figure VI-39. NO_2 FOR CASES 1, 1A1, AND 1A2 OF THE SANTA YNEZ TRAJECTORY



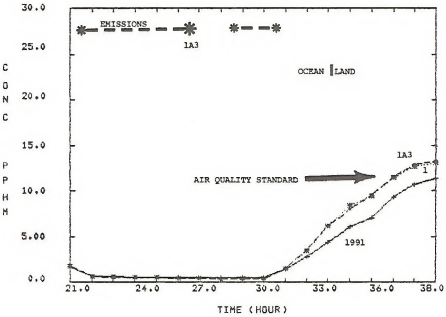
(See Figure IV-21 for Trajectory)

Figure VI-40. O_3 FOR CASES 1, 1A1, AND 1A2 OF THE SANTA YNEZ TRAJECTORY



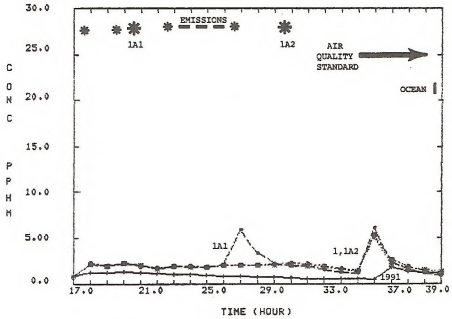
(See Figure IV-21 for Trajectory)

Figure VI-41. NO_2 FOR CASES 1 AND 1A3 OF THE SANTA YNEZ TRAJECTORY



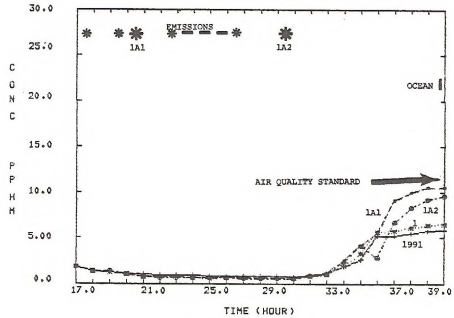
(See Figure IV-21 for Trajectory)

Figure VI-42. O_3 FOR CASES 1 AND 1A3 OF THE SANTA YNEZ TRAJECTORY



(See Figure IV-20 for Trajectory)

Figure VI-43. NO_2 FOR CASES OF THE GOLETA TRAJECTORY



(See Figure IV-20 for Trajectory)

Figure VI-44. O_3 FOR CASES OF THE GOLETA TRAJECTORY

D. Summary of Impacts

1. Inert Pollutant Modeling

The Climatological Dispersion Model (CDM) was used to estimate annually averaged concentrations of nitrogen dioxide (NO_2), sulfur dioxide (SO_2) and total suspended particulates (TSP), for which there are annual air quality standards. Using worst-case assumptions, offshore emissions sources and possible onshore gas processing plants generally should not lead to the violation of any annual ambient air quality standards (AAQS) although they could aggravate existing high concentrations in some coastal areas. Also, in some of the zones, onshore concentration increments of NO_2 and SO_2 from offshore activities could marginally exceed the proposed Department of the Interior (DOI) significance levels. Future ambient levels of TSP would be minimally increased by OCS activities. Emissions from these activities are not expected to result in onshore TSP increments exceeding the proposed DOI significance levels.

The hypothesized onshore gas plant which would service the Santa Maria OCS zone could exceed a designated Prevention of Significant Deterioration (PSD) limit (namely, the SO_2 limit of 20 $\mu g/m^3$) in the modeled peak emissions year. The concentration increments from the hypothesized gas processing plants to service the Eel River, Point Arena, and Santa Cruz OCS zones may also be of concern with respect to PSD limits for SO_2, although available data do not indicate that future ambient levels of SO_2 would be near the national AAQS.

Computed annual concentrations are for the peak emissions years of each zone. Concentrations onshore resulting from offshore activity would decrease considerably within a few years of peak activity. The decline in emissions rates from the gas processing plants would be somewhat slower. No absorption of nitrogen and sulfur oxides by the ocean surface is assumed, even though these pollutants are highly soluble in water. The CDM model has not been validated, but probably overpredicts concentrations, perhaps by as much as an order of magnitude.

The PT series of Gaussian models --PTMTP, PTMAX, and PTDIS-- were used to estimate one hour average concentrations of NO_2, SO_2 and carbon monoxide (CO) for estimated worst case emissions and meteorological assumptions. Concentrations for other averaging periods are estimated from one hour averages.

As modeled, onshore increments of NO_2 could represent a significant portion of the California one-hour standard (DOI has not proposed a short-term NO_2 significance level). However, these short-term NO_2 onshore concentrations are expected to be unrealistically high based on the use of worst-case assumptions. For example, platform installation at the three-mile limit is unlikely. In addition, maximum ship activity associated with the installation of platforms was assumed; a lower, more realistic assumption would markedly reduce onshore NO_2 concentrations.

The California 24 hour AAQS (100 $\mu g/m^3$) for TSP is presently being violated in four of the five onshore areas near the respective OCS zones; in all these cases, OCS-related activities would minimally exacerbate an existing condition. DOI significance levels for 24 hour SO_2 and TSP increments could be exceeded (in most cases by only a marginal amount) in some of the zones (Point Arena and

Santa Maria for SO_2; Eel River, Point Arena and Bodega for TSP). Hydrogen sulfide (H_2S) increments from an onshore gas processing plant located in Santa Maria are not expected to result in a violation of the California one-hour standard.

In the event that all worst-case assumptions were to hold (a statistically unlikely event), such an event could only occur during the peak emissions year in any one zone. This would be concurrent with the peak production year for three of the pollutant species examined; for the other three species, peak emissions would occur a year or two earlier.

Computations for averages longer than one hour assume an atypical steadiness of wind speed and direction. Again, more realistic assumptions would lower computed concentrations. Concentrations would further decrease in years following peak petroleum and gas production.

Taking into account all of the factors discussed above, there is little probability that any short-term air quality standard would be violated as a result of OCS activity even during peak emissions years. (There is, however, a possibility that proposed DOI significance levels may be exceeded occasionally under worst case conditions.)

2. Reactive Pollutant Modeling

The Reactive Air Pollutant Transport (RAPT) model was used to simulate ozone and nitrogen dioxide production from potential emissions of hydrocarbons and nitrogen oxides. Ozone increments based on modeling runs of the 17 trajectories formulated for use in Lease Sale No. 53 photochemical simulations varied from none through 3 pphm. Most increments were less than 1 pphm. All cases assumed worst-case meteorology insofar as it could be determined from available data. Highest ozone increments resulted from the hypothetical trajectories applied to modeling North Coast OCS emissions. It is estimated that worst-case meteorology, as used in the study, can occur on one or more days during the summer off each OCS zone.

Some of the future baselines used in determining incremental ozone from possible peak year OCS Lease Sale No. 53 activities are above state or federal ozone standards. One modeling case represents a baseline just below the state one-hour standard (0.10 ppm ozone) with the simulation resulting in ozone of 0.103 ppm. There were two similar cases relative to the national standard (0.12 ppm ozone). (The national standard must be exceeded twice within one year, however, to represent a violation.) All trajectories modeled indicated that volatile organic compounds could travel from the OCS emission area to an attainment or nonattainment area within 36 hours (DOI's proposed significance criterion). Since San Luis Obispo County, the San Francisco Bay Area, and perhaps the North Coast Air Basin may be marginally in attainment of the ozone standards, the modeling suggests that potential ozone increments from unmitigated OCS emissions could be of concern with respect to maintaining attainment status.

Accidents were also analyzed for possible ozone effects. A total of 24 cases were run. Ozone increments varied from more than 0.14 ppm for hypothetical meteorology to none for some documented trajectory constructions. Major accidents have low probability of occurring during the life of OCS development and production in each zone. The probability that concurrent worst case meteorology would also occur is even smaller.

3. Other Effects

Sulfur and nitrogen oxides can react with particulates, water vapor and ozone to form aerosols. Light scattering off aerosols with diameters in the submicron range (less than one millionth of a meter) can reduce visibility ranges. The modeling of visbility effects is not very advanced; however, it seems likely that the emission levels estimated in this study would not result in any measurable degradation of visibility.

Another potential effect of OCS Lease Sale No. 53 emissions relates to agricultural damage. The national secondary air quality standards have been set so as to protect public welfare, including protection of aesthetic values, and of property and vegetation from physical damage. The secondary standards, which are at least as stringent as the primary standards (see Table III-1), serve as a general threshold to protect public welfare. Plant species, however, have various sensitivities to air pollution.

As long as areas of California are not in attainment of the primary standards, annual agricultural losses will continue to be in the range of many millions of dollars. Any increase in air pollutant levels could result in continued crop stress and dollar loss. The effect of unmitigated OCS Lease Sale No. 53 emissions upon agriculture would depend upon the degree of attainment of air quality standards in the onshore areas near each OCS zone. In general, the effects should be small by reason of anticipated mitigation of Lease Sale No. 53 emissions (discussed in Chapter VII).

The use of the natural gas produced offshore could provide a positive beneficial effect on air quality. The gas could be utilized both directly on the platforms to replace more polluting liquid fuels and onshore to replace liquid or solid fuels in populated areas. Reducing onshore (versus offshore) emissions through the use of OCS natural gas could be of more value to onshore air quality maintenance and attainment efforts. Certainly, fuel switching involving natural gas produced offshore would be more beneficial than reinjecting the gas and not extracting it later, or extracting it with a significant energy consumption penalty.

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VII. MITIGATION MEASURES

A. Introduction

A wide range of methods could be successfully employed to mitigate any air emission impacts resulting from projected OCS Lease Sale No. 53 emission sources and operations. These control techniques generally fall into one of two broad categories: technological controls and operational strategies. Technological controls are mechanical devices or equipment modifications which prevent the formation of pollutants or their emission to the atmosphere. Examples include: devices such as scrubbers, catalytic reactors, and filters which remove pollutants from exhaust gases prior to their discharge to the atmosphere; vapor recovery systems which reduce hydrocarbon emissions during tanker offloading and loading; operational and maintenance practices which are particularly appropriate for reducing fugitive hydrocarbon losses; and modifications or control of combustion processes which can reduce a majority of exhaust emissions.

Operational strategies would provide a second, and entirely different means of reducing air pollution impacts. The intent of most operational strategy measures is not necessarily to reduce emissions directly (although they may in fact do that), but to reduce the perceptible impacts of pollutant emissions. Examples include scheduling pollutant emitting operations during hours when the emissions impacts would be limited, and restricting certain activities during periods of adverse meteorology. Further operational constraints would involve the careful planning and selection of sites for tanker operations, refineries, and storage facilities. Examples include: siting such facilities in non-populous regions; in areas with meteorology which favors rapid and thorough dispersal of pollutants; and in locations remote from other pollutant emitting industries (in order to eliminate cumulative impacts). More extreme operational strategies for the mitigation of OCS emissions include the restriction of specific activities, and the denial of onshore construction or operation permits in identified high impact zones.

The following sections discuss the expected sources of OCS Lease Sale No. 53 emissions and their relative ranking in terms of daily emissions for each of the pollutants studied. Economically feasible technological measures available for controlling emissions from these sources now or in the near future are assessed. Operational strategies or controls which do not directly involve the use of specific equipment or technology are identified. Finally, feasible control measures are applied to specific projected OCS Lease Sale No. 53 onshore air quality impacts and evaluated as to effectiveness and enforceability. It should be stressed that this information is presented only with the intent of cataloging potential mitigation measures, not of recommending any device or strategy.

B. Major Emission Sources Associated with OCS Oil and Gas Development - Lease Sale No. 53

To provide a general sense of how much specific emission sources contribute to total projected Lease Sale No. 53 emissions, emission sources for all the pollutants are tabulated and ranked in terms of estimated daily emissions (lbs/day) for both peak production year and peak emission year (Tables VII-1 and VII-2, respectively). Listed under each major pollutant are the activity in question, the type of equipment generating the emissions and whether the

emission source is mobile or stationary. Where applicable, ranked activities are footnoted to provide more specific information on projected Lease Sale No. 53 scenarios.

1. Hydrocarbon (THC) Emission Sources

Hydrocarbon emissions can be expected from all phases of OCS Lease Sale No. 53 activities; however, the two largest estimated sources of hydrocarbons would both be related to production and thereby would have a potential impact over a substantial time period. Tanker loading losses are expected to be the largest source of hydrocarbons. Hydrocarbon emissions from gas processing operations, in particular, fugitive emissions from vents and seals and exhaust emissions from direct-fired driers, would be almost as great. Gas processing would be the largest source of hydrocarbons, however, in those transportation scenarios not utilizing ships. Fugitive losses from valves, seals, oil-water separators, etc. and unburned hydrocarbons in the exhaust of the various power-producing engines or turbines would also contribute to overall hydrocarbon emissions. Table VII-1 lists the basic types of hydrocarbon emission sources expected during the peak production year in the order in which each source would contribute to the total.

2. Nitrogen Oxide (NO_x) Emission Sources

Nitrogen oxides would be emitted as a result of power generated to carry out OCS activities for the drilling, production and processing of oil and gas. Combustion systems projected for Sale No. 53 operations would include reciprocating diesel engines, diesel-fired turbines, gas-fired turbines, and boilers (which may use a range of liquid fuels). Boilers and reciprocating engines would be used to drive ships, boats and barges; whereas turbines and reciprocating engines would be used to power such stationary sources as generators, pumps and compressors.

In a given zone, nitrogen oxide emissions may peak both during the development phase, when intensive drilling and construction occur, and during the peak production period. Tables VII-1 and VII-2 show the various types of activities projected to occur at these two times and the relative contribution of each source to the overall emissions.

3. Sulfur Oxide (SO_x) Emissions Sources

Sulfur oxides from OCS oil and gas development would be emitted primarily as a result of power generation operations. Therefore, turbines and reciprocating engines located offshore are expected to be significant stationary sources of sulfur oxides. Tankers, tugboats, barges, supply and crew boats would likely be the major mobile sources of sulfur oxides. Another potentially substantial sulfur oxide source would be any sulfur recovery process associated with gas processing. The incorporation of a sulfur recovery unit, which was considered to represent the best current engineering practices, is in itself a mitigation measure for hydrogen sulfide (H_2S) as well as sulfur dioxide (SO_2). The amount of sulfur oxides estimated to be released as a result of OCS Lease Sale No. 53 activity was based on the evaluation of the anticipated effectiveness of the Claus sulfur recovery plant to be installed on Exxon's Hondo platform: "This unit will remove greater than 90 percent of the H_2S separated from the stabilized crude oil and sour fuel gas .... [This] unit reduces the overall project SO_2 emissions by approximately 92 percent" (Dames and Moore, 1979).

Table VII-1. GENERAL RANKING OF PROJECTED OCS LEASE SALE NO. 53 EMISSION SOURCES ON A DAILY BASIS DURING PEAK PRODUCTION YEAR[1]

Sources Ranking	Pollutant					
	THC	NO_x	SO_x	CO	TSP	H_2S
Largest Emitter	Tankers Loading at OS&T[4] (Evaporative Stationary Sources)	Support Activities[2] (Diesel Engines-Mobile Sources)	Power Generation (Diesel Turbines-Stationary Sources)	Support Activities (Diesel Engines-Mobile Sources)	Support Activities (Diesel Engines-Mobile Sources)	Gas Processing (Evaporative Losses-Stationary Sources)
	Gas Processing[3] (Evaporative Losses-Stationary Sources)	Power Generation (Diesel Turbines-Stationary Sources)	Gas Processing (Combustion-Stationary Sources)	Miscellaneous Onshore Emissions[7] (Diesel & Gasoline Vehicular Engines-Mobile Sources)	Power Generation (Diesel Turbines-Stationary Sources)	Tanker Loading at OS&T (Evaporative Losses-Stationary Sources)
	Platform Operations (Evaporative Losses-Stationary Sources)	Onshore Gas Processing (Combustion-Stationary Sources)	Tankers in Transit[6] (Resid. Oil Fired Boilers-Mobile Sources)	Power Generation (Diesel Turbines-Stationary Sources)	Tankers in Transit[6] (Resid. Oil Fired Boilers-Mobile Sources)	
	Tankers in Transit[6] (Resid. Oil Fired Boilers-Mobile Sources)	Power Generation for Oil Pumping[5] (Diesel Turbines-Stationary Sources)	Tankers Loading at OS&T (Resid. Oil Fired Boilers-Stationary Sources)	Power Generation for Oil Pumping[5] (Diesel Turbines-Stationary Sources)	Power Generation for Oil Pumping[5] (Diesel Turbines-Stationary Sources)	
	Power Generation (Diesel Turbines-Stationary Sources)	Development Drilling (Diesel Engines-Stationary Sources)	Support Activities (Diesel Engines-Mobile Sources)	Development Drilling (Diesel Engines-Stationary Sources)	Tankers Loading at OS&T (Resid. Oil Fired Boilers-Stationary Sources)	
	Support Activities (Diesel Engines-Mobile Sources)	Tankers in Transit[6] (Resid. Oil Fired Boilers-Stationary Sources)	Power Generation for Oil Pumping[5] (Diesel Turbines-Stationary Sources)	Oil Processing (Combustion-Stationary Sources)	Development Drilling (Diesel Engines-Stationary Sources)	
	Power Generation for Oil Pumping (Diesel Turbines-Stationary Sources)	Miscellaneous Onshore Emissions (Diesel & Gasoline Vehicular Engines-Mobile Sources)	Development Drilling (Diesel Engines-Stationary Sources)	Tankers in Transit[6] (Resid. Oil Fired Boilers-Mobile Sources)	Miscellaneous Onshore Emissions[7] (Diesel & Gasoline Vehicular Engines-Mobile Sources)	
Smallest Emitter	Miscellaneous Onshore Sources[7] (Diesel & Gasoline Vehicular Engines-Stationary Sources)	Oil Processing (Process Heater-Stationary Sources)	Miscellaneous Onshore Sources[7] (Diesel & Gasoline Vehicular Emissions-Mobile Sources)	Tankers Loading at OS&T (Resid. Oil Fired Boilers-Stationary Sources)	Power Generation for Oil Pumping[5] (Diesel Engines-Stationary Sources)	
		Offshore Gas Processing (Combustion-Stationary Sources)	Oil Processing (Combustion-Stationary Sources)			

Table VII-1 (continued)

Sources Ranking	Pollutant					
	THC	NO_x	SO_x	CO	TSP	H_2S
Variable	Spills Blowouts Fires Seals (Compressors, valves, pipelines) Water Treatment	Fires	Fires	Fires	Fires	Blowouts

1. Projected peak production years in each zone are as follows: Bodega, 1987; Santa Maria, 1991; Eel River, 1987; Point Arena, 1989; and Santa Cruz, 1990. There may be variations in the ranking of specific activities within the different zones.

2. The impact of emissions from mobile sources would not be the same as the impact of emissions from stationary sources since the mobile source emissions would be dispersed over a much larger area.

3. Gas processing would occur offshore in Transportation Scenarios 1, 2 and 3 and onshore in Scenario 1A with the exception of the Bodega zone since recovery of gas at this zone is not expected.

4. Tankers or barges projected for use in specific scenarios are described elsewhere in the text (see Chapter V). Within a single 24-hour period, a ship generally would only have time to load and to maneuver about the platform: it would not usually be able to move into the open sea at any distance from the OS&T.

5. Pipelines are projected for gas transport in all scenarios. They are used for oil only in Scenarios 1 and 1A at Santa Cruz and Santa Maria. Thus, these values are applicable only for these specific cases.

6. This activity would be applicable for all zones only in Transportation Scenario 2 and for Point Arena and Bodega in Scenarios 1 and 1A.

7. In Transportation Scenarios 1, 1A and 2 for Bodega, the barge would reach San Francisco and contribute to these emissions.

Table VII-2. GENERAL RANKING OF PROJECTED OCS LEASE SALE NO. 53 EMISSION SOURCES ON A DAILY BASIS DURING PEAK EMISSION YEARS[1]

Sources Ranking	Pollutant[2]		
	NO_x	CO	TSP
Largest Emitter	Support Activities[2] (Diesel Engines-Mobile Sources)	Support Activities (Diesel Engines-Mobile Sources)	Support Activities (Diesel Engines-Mobile Sources)
	Platform Installation (Diesel Engines-Stationary Sources)	Platform Installation (Diesel Engines-Stationary Sources)	Platform Installation (Diesel Engines-Stationary Sources)
	Production Power Generation (Diesel Turbines-Stationary Sources)	Production Power Generation (Diesel Turbines-Stationary Sources)	Production Power Generation (Diesel Turbines-Stationary Sources)
	Development Drilling[3] (Diesel Engines-Stationary Sources)	Miscellaneous Onshore Activities (Diesel and Gasoline Vehicular Emissions - Mobile Sources)	Tankers[5] (Resid. Oil Fired Boilers)
	Power Generation for Oil Pumping[4] (Diesel Turbines-Stationary Sources)	Development Drilling (Diesel Engines-Stationary Sources)	Power Generation for Oil Pumping[4] (Diesel Turbines-Stationary Sources)
	Tankers[5] (Resid. Oil Fired Boilers)	Power Generation for Oil Pumping[4] (Diesel Turbines-Stationary Sources)	Tankers[7] (Resid. Oil Fired Boilers)
	Miscellaneous Onshore Emissions (Diesel and Gasoline Vehicular Engines-Mobile Sources)	Tankers (Resid. Oil Fired Boilers)	Oil Processing (Process Heaters-Stationary Sources)
	Tankers[6] (Resid. Oil Fired Boilers)		
Smallest Emitter	Offshore Gas Processing (Process Heaters-Stationary Source)		
Variable	Fires	Fires	Fires

Table VII-2 (continued)

1. The peak emission year is expected to vary among the five zones. For the Santa Maria area, the year of interest would be 1989; for Bodega, 1985; Eel River, 1985; Point Arena, 1989; and Santa Cruz, 1988.

2. THC and H_2S emission sources are omitted since the major sources of these pollutants would be production oriented activities which are not projected to begin until construction is well underway. SO_x emissions would also be at a maximum during the production phase.

3. Emissions from mobile sources would be dispersed over a wide area.

4. This would not be true in Transportation Scenario 1A. Onshore gas processing would require additional power generation, expected to be provided by diesel turbines, which would produce more NO_x than development drilling.

5. Emissions from power generation for oil pumping would be applicable only in Scenarios 1 and 1A for the Santa Cruz and Santa Maria zones, where transport of oil by pipeline is anticipated.

6. Tankers are projected for use in Transportation Scenarios 2 and 3. In Scenario 2, the activity of concern would be sea passage, while in Scenario 3, loading emissions are estimated to be greater.

7. In Scenario 2, emissions during loading would be only slightly greater than emissions from tanker maneuvering about the OS&T.

8. In Scenario 3, tankers in transit would produce slightly more emissions than tanker maneuvering about the OS&T.

Under Transportation Scenario 1A, gas processing plants would be located onshore. In all other transportation scenarios, gas would be processed offshore. (Refer to Chapter V for a discussion of transportation scenarios.) Table VII-1 lists the types of operations which would contribute to sulfur oxide emissions.

4. Carbon Monoxide (CO) Emission Sources

Carbon monoxide emissions are estimated to be highest during two periods in the development of an OCS zone: 1) when drilling and construction activities are at a maximum level; and 2) when peak production is attained. The double peak of carbon monoxide emissions is due to the increased requirements for power generation associated with both the maximum construction and production periods. As with nitrogen oxides, reciprocating diesel engines, diesel-fired turbines, gas-fired turbines, and boilers would be the primary emission sources. Tables VII-1 and VII-2 list, in order of quantity emitted, the most significant sources of carbon monoxide expected from OCS Lease Sale No. 53 activities.

5. Particulate Matter (TSP) Emission Sources

Particulate matter, in addition to nitrogen oxides and carbon monoxide, would also be emitted in the exhaust of the power generating turbines, engines or boilers. Particulates would be emitted at their highest levels when the greatest amount of construction and development drilling occurs and again when the zone has reached its maximum production rate. The support activities of supply boats, crew boats, and similar mobile sources would produce the largest share of pollutants during the development phase. During the production phase, the offshore stationary sources would be the primary source of particulate matter. Tables VII-1 and VII-2 show the expected types of particulate matter sources ranked according to quantity emitted.

6. Hydrogen Sulfide (H_2S) Emission Sources

Emissions of hydrogen sulfide are expected whenever fugitive hydrocarbon losses occur. With respect to OCS Lease Sale No. 53 oil and gas development, hydrogen sulfide emissions are estimated to result from vents in the proposed gas processing plants and, to a much lesser extent, from tanker loading and breathing losses.

C. Technological Control Measures for Mitigation of OCS Emissions

1. Hydrocarbon and Hydrogen Sulfide Emissions

As indicated in Table VII-1, the major sources of hydrocarbon emissions during the peak production year are 1) evaporative losses from the transfer and storage of petroleum liquids, 2) gas processing fugitive and fuel combustion losses, 3) fugitive losses from other processing activities, and 4) power generation fuel combustion. Hydrogen sulfide emissions would also occur as a result of processing and tankering operations. Therefore, mitigation measures that reduce hydrocarbon emissions would be effective in reducing emissions of hydrogen sulfide.

a. Evaporative Losses

Tanker loading and offloading, tanker ballasting and the storage of petroleum liquids would be the major sources of hydrocarbon evaporative emissions associated with OCS Lease Sale No. 53. Hydrocarbon and hydrogen sulfide emissions from tanker loading at offshore storage and treatment (OS&T) facilities could be greatly reduced by installing a vapor balance line. Tanker loading at these offshore facilities would result in vapors in the shuttle tanker cargo tanks being displaced by crude oil loaded from the OS&T. With a vapor balance line system, vapors would be collected and sent to the OS&T crude oil storage tanks to fill the space left by the offloaded crude oil. Such a system has been proposed by Exxon Oil Corporation in conjunction with its Platform Hondo in the Santa Barbara Channel. According to Exxon, vapors collected and sent to the OS&T crude oil storage tanks will be recovered and sent to the fuel gas system for H_2S removal and eventual burning in the OS&T turbine generators. Exxon will provide inert gas for operation of the vapor balance line as a safety consideration (Dames and Moore, 1979).

Theoretically, vapor recovery systems other than vapor balance would also be extremely effective control measures for reducing tanker-related hydrocarbon emissions. However, few if any such systems, outside of Exxon's proposed use of a vapor balance line, are currently in use for tanker loading operations.

Vapor recovery control technology for gasoline loading of barges has been recently evaluated (Pullman Kellogg, 1979). The study compared the relative efficiencies of various combinations of control techniques and safety methods. Carbon adsorption coupled with inert gas generation was found to be the most cost-effective method for reducing hydrocarbon emissions. Cost effectiveness, expressed in pounds of hydrocarbons controlled per dollar of annualized cost, was found to increase with increased throughput. Safety measures for the vapor recovery equipment were found to be the largest contributors to the capital and annualized cost of the systems.

Before vapor control equipment can be utilized on vessel facilities, the U.S. Coast Guard would likely require that cargo tank vapors be completely incapable of combustion. The most probable method to guard against burning would be to blanket the tanks with inert flue gas from the ship's boilers or from an independently fired inert gas generator. The U.S. Coast Guard intends to implement the 1978 Intergovernmental Maritime Consultative Organization protocols for new and existing tankers, which could affect 77 percent of U.S. flag domestic trade tankers. Specifically, by mid-1983 crude oil tankers larger than 20,000 DWT capacity would be required to have inert gas systems. However, a U.S. crude oil tanker with a capacity between 20,000 and 30,000 DWT which does not have crude oil washing may be exempted if the Coast Guard determines that retrofit of an inert gas system is impractical. Retrofit costs are estimated to be $900,000 for a 40,000 deadweight ton (DWT) tanker. The estimated additional cost for a closed gauging system is $32,000 for a 35,000 DWT tanker (CARB, 1978). These costs could conceivably be interpreted as too great and thereby render retrofit "impractical."

In the absence of vapor recovery or vapor balance systems, the following procedural controls could provide feasible and practical means of reducing the impact of evaporative losses from tanker loading operations. Initial investigations indicate that vapor-freeing the ballasted and empty cargo tanks while in transit at sea could potentially reduce in-port tanker loading losses from

50 to 60 percent. This does not reduce total emissions, but it does disperse them more and thereby lessen the maximum impact of in port emissions. Emission reductions could also be gained by slow initial loading, fast bulk loading, and slow final loading. Slow loading reduces vapor turbulence while fast loading reduces tank filling time and thus the time available for additional vapor formation. It is estimated that the above loading procedures could reduce loading losses by 60 to 80 percent (Radian Corporation, 1978).

The use of segregated ballast tankers would reduce evaporative emissions from ballasting operations while the ballasting of cargo tanks at sea would displace the evaporative emissions from near shore to sea, thus reducing onshore impacts. In addition, in-port procedural changes could reduce hydrocarbon emissions. These procedural changes could include quick unloading of cargo, careful stripping of the residual product from the empty tank bottom and prompt partial ballasting (additional ballast could be taken on when out of port). Capital costs for such procedural changes would be minimal; however, an increase in operating costs would be expected.

Crude oil storage would be provided on the OS&Ts, or in the case of Transportation Scenario 1A, on shore at the landfalls of oil pipelines from the Santa Cruz and Santa Maria zones. The cargo holds of the OS&T are expected to serve as storage tanks after they are interconnected by a manifold system to control hydrocarbon losses. It is not known at this time whether proposed onshore tanks would be fixed roof or floating roof. Fixed roof tanks, if uncontrolled, can lose 3 to 5 times as much hydrocarbons from breathing losses as can a floating roof tank standing under the same conditions. Working losses from a fixed roof tank are at least a hundred times greater than withdrawal losses from a floating roof tank. Overall, emissions from fixed roof tanks can account for 80 percent of the total hydrocarbon emissions from all types of storage tanks.

Control techniques for fixed roof tanks would include replacing older tanks with newer tanks which have lower loss rates (e.g. floating roof tanks, tanks with internal floating covers, and variable vapor space tanks equipped with vapor recovery systems), retrofitting older tanks with control technologies such as internal floating roofs and vapor recovery systems, and the use of conservation vents. The installation of floating roofs to replace fixed roofs or the use of vapor recovery for fixed roof tanks is considered a "reasonably available control measure" by EPA and the California Air Resources Board (CARB). A 95 percent control efficiency is estimated.

Table VII-3 indicates the cost-effectiveness of installing floating roofs on fixed roof storage tanks. Given a true vapor pressure of 2.8 psia for crude oil (EPA, 1977), retrofitting a fixed roof tank with a floating roof would probably be a cost-effective or a "breakeven" measure for the three tank sizes described.

Floating roof tanks as a control measure are intrinsically safer than the use of vapor control systems, although the latter are a more effective means of reducing hydrocarbon emissions. Where no vapor recovery system is used, painting the storage tanks white would minimize breathing losses. In addition, proper maintenance to ensure tight cover fit over storage tanks would decrease emissions.

b. Fugitive Emissions

Pumps, compressors, valves, flanges, blinds, sampling points, horizontal tanks for liquid-gas and oil-water separation, and flares could all result in fugitive hydrocarbon emissions. One study estimated that 89 percent of all hydrocarbon emissions at an oil-gas production facility were due to leaks (Radian Corporation, 1978). The magnitude of projected emissions from Sale No. 53 gas processing equipment confirms that leaks are a primary stationary hydrocarbon emissions source. At present, proper design and maintenance are the major control techniques recommended for the control of fugitive emissions.

Pump seals are generally one of the principal sources of fugitive emissions in oil production operations. Emissions from centrifugal pumps could be reduced by 33 percent by replacing packed seals with mechanical seals (Radian Corporation, 1978). This measure requires that volume throughputs of pumps and compressors be high enough so that centrifugal fluid transport systems could be used, which then allows the use of a mechanical seal rather than a packing seal. Two types of mechanical seals recommended for compressor use are the labyrinth seal for gas service and the oil-film seal for liquid service (DOI, 1978). The cost of installing a mechanical seal on an existing pump, including a cooler, labor, and materials is about $2,000-$2,500 (Radian Corporation, 1978). Emissions from reciprocating pumps could be controlled by installing dual packed seals with provisions to vent the volatile vapors that leak past the first seal into a vapor recovery system.

Emissions could further be reduced by frequent inspection and corrective maintenance. Emission reducing maintenance measures would include replacing packings in valves, replacing gaskets for valves and flanges, cleaning and reseating pressure relief devices and tieing them into the flare system, covering drains, and installing more modern equipment. The San Luis Obispo Air Pollution Control District (APCD) has estimated a 95 percent control efficiency from measures combining improved inspection and maintenance of valves and flanges at oil production fields with prompt shutdown and repair of leak sources. The Santa Barbara APCD has estimated the cost-effectiveness of control mechanisms for valves and flanges (adequate maintenance procedures and mechanical seals for pumps or compressors) to be approximately $-78, expressed as dollars per ton of hydrocarbon reduction (this figure indicates a net savings to oil plant operators).

c. Fuel Combustion

The major sources of fuel combustion related hydrocarbon emissions are projected to be tankers, tugs, barges and related mobile equipment, and diesel-fired turbines, process heaters, and heater treaters on the platforms. Proper application, installation, operation and maintenance of the combustion equipment would be the most practical means of lowering emissions. Although no cost estimates for the above measures are available, it is expected that these practices would be incorporated along with new equipment as platforms are constructed.

A second method for reducing fuel combustion hydrocarbon emissions once production is underway, would be the substitution of a cleaner burning fuel, e.g., the substitution of natural gas for distillate or diesel fuel. Table VII-4 compares the emission rates for natural gas and diesel fuels when burned in heavy duty industrial equipment. The potential for reducing emissions by

Table VII-3. COST-EFFECTIVENESS OF INSTALLING FLOATING ROOFS ON FIXED ROOF CRUDE OIL STORAGE TANKS

$ per ton of controlled substance

	Low	Medium	High
True Vapor Pressure (psia)	2.0	6.0	10.0
No. of Turnovers/Year	5	10	20
Tank Size			
10,000 bbl	220	4	-73
55,000 bbl	73	-68	-100
150,000 bbl	28	-82	-110

Source: Radian Corporation, 1978.

Table VII-4. NATURAL GAS AND DIESEL FUEL COMBUSTION EMISSION RATES FOR HEAVY DUTY INDUSTRIAL EQUIPMENT

Contaminant	Natural Gas Emission Rate ($lbs/10^6$ Btu)[1]	Diesel Emission Rate ($lbs/10^6$ Btu)[2]
Particulates	0.01	0.24
Sulfur oxides	Neg.	0.22
Nitrogen oxides	0.39	3.35
Total Hydrocarbons	0.04	0.27
Carbon Monoxide	0.11	0.73

1. Based on emission factors for electric utility turbines presented in EPA AP-42 (1977). Assumes natural gas heat content of 1,050 Btu/ft^3

2. Based on emission factors for gasoline and diesel-powered industrial equipment presented in EPA AP-42 (1977). Assumes diesel heat content of 140,000 Btu/gal.

Source: DOI, 1978.

using gas rather than a liquid fuel can be illustrated by examining the emissions associated with power generation alone in the Point Arena zone. Emissions, stated in Table V-26 for the combustion of diesel fuel are as follows: total hydrocarbons, 196 pounds/day; nitrogen oxides, 1,595 pounds/day; sulfur oxides 1,119 pounds/day; carbon monoxide, 439 pounds/day; and total suspended particulate, 196 pounds/day. If recovered gas were treated and consumed at the production site, power generation related emissions could decrease by as much as 167 pounds of hydrocarbons/day, 1,409 pounds of nitrogen oxides/day, 373 pounds of carbon monoxide/day and 188 pounds of total suspended particulates/day. The reduction in sulfur dioxide emissions would depend on the extent of desulfurization performed. If the recovered gas contained 0.8 pounds of sulfur per 1,000 cubic feet, and if 95 percent were removed, then sulfur dioxide emissions could be reduced by about 700 pounds/day.

The use of waste heat generated by stationary sources (such as gas turbines) could lower overall hydrocarbon emissions by reducing fuel consumption. The use of a heat transfer fluid and the waste heat from gas turbine exhaust could eliminate the need for direct-fired heaters used in gas and oil dehydration (Energy Resources Co., Inc., 1977). Waste heat utilization could also increase the efficiency of the power generating equipment through the use of combined gas/steam turbine power cycles. The use of a combined cycle operation, although currently in the development phase, could increase the efficiency (and correspondingly reduce emissions) of gas turbine operations from approximately 26 percent to as much as 40 percent. Waste heat utilization as a pollution control measure would result in a net savings of energy as opposed to a net increase as is common with most other mitigation measures. Although waste heat utilization as a mitigation measure has been discussed in the framework of hydrocarbon emission reductions, similar emission reductions would be expected for the other pollutants of concern.

2. Nitrogen Oxide, Carbon Monoxide and Total Suspended Particulate Emissions

Nitrogen oxides, carbon monoxide and particulates would be emitted in large quantities from the exhausts of the power-generating turbines, engines and boilers associated with OCS Lease Sale No. 53 platform operations and support activities. Although most control measures for the equipment listed above are specific for NO_x reduction, overall effectiveness in reducing carbon monoxide and particulates can usually be determined.

The two techniques currently available for the reduction of NO_x emissions are treatment of exhaust gases and combustion modification. Exhaust gas treatment includes the use of scrubbers, ammonia injection, and the use of catalytic reactors. Combustion modification comprises a much larger range of control options including injection timing adjustments, exhaust gas recirculation, water injection, the use of alternative fuels and stratified charge engines.

a. Flue Gas Treatment

Potential flue gas treatment technologies to reduce Sale No. 53 NO_x emissions would include: injection of ammonia (NH_3), steam, or hydrocarbons (sometimes in the presence of a metal catalyst); scrubbing with a solution of potassium permanganate ($KMnO_4$); and catalytic reduction of NO_x. Of these

technologies, only catalytic reduction could be effectively employed on the relatively small turbines and engines which have been historically employed on offshore platforms, and the reciprocating diesel engines used for power on ships tugboats, and barges.

The control of NO_x emissions from diesel engines is generally difficult, and conventional catalytic reactors are often ineffective in reducing the NO_x emissions to desired levels (Marshall et al., 1978). There are several reasons for this. First, such catalytic reactors were designed primarily to control hydrocarbon and carbon monoxide emissions. Second, conventional reactors require a fuel-rich exhaust if they are to function effectively, and diesel engines yield a fuel-lean exhaust. Finally, diesel engine exhaust contains large quantities of particulates which can block the active sites of the catalyst and render it ineffective.

However, recent research demonstrates that catalytic reactors which could control NO_x emissions, even from fuel-lean exhausts, are feasible (Automotive Engineering, 1977, 1978; Anderson, 1977). At least one firm plans to market a catalytic reactor designed to control NO_x emissions from diesel engines within a few months (Bryant, 1979). The reactor is expected to reduce NO_x emissions by 80 to 90 percent. The cost of the reactor is expected to add 10 to 20 percent to the price of a diesel engine. For a 300 horsepower engine, a retrofitted catalytic reactor would cost about $2,500 (Smojver, 1979).

Background information on NO_x control techniques for EPA New Source Performance Standards on Internal Combustion Engines (EPA, 1979) indicate that ammonia injection over a precious metal catalyst could reduce NO_x emissions by 90 percent. However, the cost of such a system would be high. Capital investment for a 1,000 horsepower (hp) engine could represent four percent of the engine purchase price. Also, increases in the total annual operating cost could increase the total cost by up to 25 percent. NO_x reduction by ammonia in the presence of a catalyst has not been demonstrated for stationary gas turbines (EPA, 1977).

b. Combustion Modification

Possible combustion controls for diesel engines and gas turbines projected for OCS Lease Sale No. 53 could include exhaust gas recirculation, water injection, injection timing modification, and the use of alternative fuels or water-fuel emulsions.

Exhaust gas recirculation (EGR) has been used for several years to control NO_x emissions from automobiles and has also been effectively applied to utility boilers. The EGR process reintroduces some of the exhaust gas into the combustion chamber, where it serves to lower both peak temperatures and the concentration of free oxygen, thereby reducing the production of NO_x (the production of NO_x increases rapidly with temperature). EGR can reduce automobile NO_x emissions by 50 to 60 percent. However, EGR must be closely controlled or the production of particulates is increased and engine performance deteriorates (Automotive Engineering, 1978; Marshall, 1975). Cost estimates for the retrofitting of EGR systems are unavailable, but they should cost substantially less than catalytic reactors.

The injection of water vapor into the diesel engine combustion chamber also would lower NO_x production in much the same manner as EGR, that is, by lowering

peak temperature and reducing the availability of free oxygen. If equal amounts of water and fuel were injected, NO_x emissions could be lowered by 70 percent (Marshall, 1975). Although water injection requires extra tanks for water and could cause significant corrosion, it would not diminish performance or cause increased particulate production (as does EGR).

Water-fuel emulsions may also be injected into the combustion chamber. Some researchers have attained modest NO_x reductions with this technique (Murayama et al., 1978), while others have found it unsatisfactory (Marshall, 1975). Currently, it does not appear to be a viable means of controlling NO_x emissions from diesel engines.

Retarded injection timing could also significantly lower NO_x emissions, but both fuel consumption and particulate production would increase rapidly as NO_x emissions are lowered (Marshall, 1975). EPA's support document for the recent New Source Performance Standards for internal combustion engines has identified fuel injection retard and air-to-fuel ratio changes as the most effective NO_x control techniques for diesel and gas engines, respectively (EPA, 1979). In some cases, however, particularly with naturally aspirated gas engines, applications of these NO_x control technologies could cause increased emissions of hydrocarbons and carbon monoxide as well as particulates. Carbon monoxide emissions, in particular, could be increased by as much as 160 percent.

The proposed New Source Performance Standards for internal combustion engines limit NO_x emissions from new, modified and reconstructed stationary gas, diesel and dual-fuel engines to 700, 600, and 600 ppm, respectively (EPA, 1979). This limitation would result in about a 40 percent reduction in NO_x emissions. The proposed standards would, however, increase total annualized costs to users by approximately 2 to 7 percent, with diesel and naturally aspirated gas internal combustion engines accounting for the largest increases.

The injection of water or steam into the combustion reaction is considered the most feasible control technology for reducing NO_x from stationary gas turbines (EPA, 1977). However, this control method has not really been adequately demonstrated on small production gas turbines of less than 10,000 hp. Most gas turbines used on offshore oil and gas drilling platforms have a heat input at peak capacity of less than 107.2 gigajoules per hour (about 10,000 hp). In the future, however, platforms and/or offshore storage and treatment facilities may employ considerably larger gas turbines such as the 25,000 hp turbines with water injection systems planned for Exxon's Platform Hondo.

According to background support data for gas turbine New Source Performance Standards (EPA, 1977), gas turbine NO_x emissions could be reduced by 70 percent through use of water injection. In general, a concurrent fuel consumption increase of 0 to 5 percent would be expected. However, for offshore applications, such as oil and gas drilling platforms, the overall cost increase could be as much as 7 percent. Desalination equipment might be required for offshore industrial applications to provide the high quality water necessary for water injection.

Minor amounts of hydrocarbon and carbon monoxide emissions are expected from the operation of gas turbines. Water injection control methods are not expected to result in any substantial increased emissions of these pollutants.

Particulate matter emissions from stationary gas turbines depend on the ash content of the fuel and would, in general, be minimal. However, if desired, particulate matter emission reductions of over 50 percent could be achieved by switching from diesel-fired turbines to gas-fired turbines (Energy Resources Co., Inc., 1977).

3. Sulfur Dioxide (SO_2) Emissions

Sulfur dioxide emissions are expected primarily from power generation, gas processing and tankering operations (see Table VII-1). The two main control technologies for reducing SO_2 emissions are modification of the fuel sulfur content and flue gas desulfurization. SO_2 emissions from the diesel-fired gas turbines anticipated for platform power generation would be best controlled by burning low sulfur fuels (EPA, 1977). The same holds true for ships whether they require residual oil or diesel for fuel. The use of low sulfur fuels is considered more economical in the long run since increased maintenance costs associated with the firing of heavy fuel oils are greater than the savings that would be realized by buying the cheaper heavy or residual fuel oils. New Source Performance Standards for onshore stationary gas turbines would limit the sulfur content of fuel to 0.8 percent by weight. CARB's proposed Model Rule for the control of marine vessel fuel sulfur content would require vessels operating in California Coastal Waters to use fuels having a sulfur content of 0.5 percent by weight or less. Flue gas desulfurization to control SO_2 emissions from gas turbines is not considered reasonable by EPA since control costs are about 2 or 3 times more expensive than the gas turbine itself (EPA, 1977).

Exxon has identified the OS&T acid gas incinerator associated with Platform Hondo as one of its largest projected sources of SO_2 emissions (Dames & Moore, 1979). Exxon anticipates that installation of a Claus sulfur recovery system on the OS&T would eliminate 93 percent of the SO_2 emissions from the incinerator. Installation is contingent upon receipt of U.S. Coast Guard approval.

D. Operational Strategies

The operational strategies addressed here are those measures that, although not usually included in traditional mitigation requirements such as Best Available Control Technology, could be effective in reducing emissions and/or air impacts from OCS operations. Operational strategies include using the best feasible operating techniques, regulating mobile source activities by such actions as limiting the time and place for tanker loading operations, and requiring onshore emissions "trade-offs" in connection with proposed OCS development. Because of the long-range transport capabilities of hydrocarbons and nitrogen oxides and their potential role in aggravating current onshore ozone violations, most of the following measures center around the controlling nitrogen oxide and hydrocarbon emissions and/or impacts.

1. Controls for Platform Operations

As described earlier, platform emissions of hydrocarbons and hydrogen sulfide would result primarily from fugitive losses, while nitrogen oxide, carbon monoxide, sulfur dioxide and particulate emissions would result from power generation. The most feasible control measures for these emissions are technological in nature. Proper maintenance and operation according to the manufacturer's recommendations are probably the most applicable quasi "non-technological" control measures for reducing actual emissions. While not

effective in reducing emissions, siting and spacing of platform locations to reduce short-term onshore impacts may also constitute an effective operational strategy.

2. Controls for Transport Operations

Tanker loading and associated activities plus the boats, ships and barges required for construction and support activities are assumed to be the major emission sources associated with transport operations. Some possible operational strategies for controlling or limiting the short-term onshore impact of these emissions include:

- restricting or prohibiting vessel activities (especially tanker loading) during the early morning hours when the photochemistry is conducive to ozone formation;
- limiting the number of ships that can load or unload at any one time in a given geographic area;
- restricting or prohibiting vessel activities during air pollution episode days;
- requiring segregated ballast capacity of sufficient quantity such that tankers would not need to take on ballast while in port;
- restricting conditions for purging or gas-freeing a tanker;
- transporting oil by pipeline to eliminate the need for tankering.

Short-loading a tanker has been suggested in previous studies on OCS emissions as a mitigation measure for reducing hydrocarbon emissions. A recommendation for short loading was originally included in the proposed Air Quality Maintenance Plan for Santa Barbara County but has since been deleted. In a written response to Santa Barbara's request for comments, dated March 27, 1979, the Western Oil and Gas Association presented the following technical assessments of short loading and the potential restriction on multiple tanker loadings (Santa Barbara County, Office of Air Quality Planning, 1979):

> With regard to the short-loading provision, the district's estimate that this practice would result in a 34% reduction in emissions is in error. In actual practice, requiring short-loading of tankers on trade routes similar to those involved here, may result in increases in emissions after the first loading in addition to creating safety hazards and increasing the cost of petroleum operations leading to higher product costs for the consumer.
>
> Tanker short-loading provisions are environmentally unsound because decreasing the amount of crude oil in the cargo tanks allows more empty volume to remain in the tanks to become laden with hydrocarbon vapors. This, of course, results in an increase in hydrocarbon emission during the second loading of the tanker since these vapors will still be on board when the ship returns....

In addition, it is considered poor marine practice to operate vessels with slack tanks since swash damage may occur. In rough seas, cargo has more room to slosh around in partially filled tanks than in fully loaded tanks. Naval architects refer to this as the 'free surface effect.' Under extremely rough conditions this cargo movement can increase the likelihood of damage to vessel structures.

Short-loading all vessels would clearly be less efficient and more costly than fully utilizing vessel capacity because more port calls would be required to handle the same volume of crude. This will increase traffic congestion and attendant safety and pollution risks simply because tanker loadings and discharges will be performed more frequently. The greater number of trips will also lead to increased emissions.

The second recommendation concerning tankers is to prohibit multiple or simultaneous tanker loadings in the channel. We believe the inclusion of this measure in the plan is unnecessary as at the present time, the number of tanker loadings in the channel does not result in a significant incidence of multiple tanker loading. In addition, we would point out the prohibiting concurrent tanker loadings will not result in any reduction in the amount of emissions discharged - only the timing of such emissions. While this regulation might on some days decrease hydrocarbon emissions and thereby lead to lower oxidant levels, it would increase oxidant levels if loadings are delayed to other days when meteorological conditions may be less favorable.

According to most of the state air pollution control districts' New Source Review Rules, the definition of "stationary source" includes liquid cargo vessels unloading or loading at marine terminals. Emissions from such vessels would include those from engine operations, purging or venting of vapors, and loading, storage, processing and transfer of organic liquid cargo. In some areas, the definition incorporates those marine cargo vessels operating within the California Coastal Waters. For those sources falling under New Source Review regulations, emissions offsets or "trade-offs" may constitute an effective mitigation measure.

3. Controls for Onshore Operations

The only onshore facilities anticipated for Lease Sale No. 53 development would be inland gas processing plants projected under Transportation Scenario 1A. These facilities would have to meet the applicable New Source Review requirements, including emissions trade-offs if sited in a nonattainment area, as set forth by the local Air Pollution Control District.

E. Mitigation for Potential Onshore Impacts

Proposed mitigation measures for OCS Lease Sale No. 53 projected onshore impacts as determined by the air quality impact assessment (Chapter VI) are based on the Department of the Interior (DOI) proposed regulations for offshore

oil and gas operations and on federal (EPA), state and local air pollution rules and regulations for onshore operations. As described previously under regulatory considerations (Chapter III), the draft DOI regulations would require OCS lessees to determine through modeling whether air emissions from OCS development and production activities in federal waters would result in onshore pollutant concentrations above specified significance levels. If significance levels were exceeded, either Best Available Control Technology (BACT), additional control technology or offsets would be required depending on whether the onshore area was designated attainment or nonattainment for the pollutants in question. OCS-related onshore facilities sited in attainment areas would be required to comply with PSD regulations while those facilities sited in nonattainment areas would be required to comply with EPA's Emissions Offset Policy, which is generally reflected by the New Source Review Rules of California's local APCDs.

Mitigation measures as described under the various sets of regulations would either require BACT or additional control technology, or offsets that would be determined by the OCS lessee or operator of the proposed onshore site. BACT has not been previously defined for the mitigation of OCS oil and gas development emissions. Since BACT must consider energy, environmental and economic impacts, it would be applied on a case-by-case basis. In general, the requirements for BACT must be at least as stringent as applicable New Source Performance Standards. The California Air Resources Board has indicated a future intent to study and identify BACT for controlling OCS-related emissions (Rubenstein, 1979).

Until BACT is defined, a variety of technological and operational control measures could be potentially utilized to mitigate those projected onshore impacts indicated by the air quality impact assessment as possibly resulting from OCS Lease Sale No. 53 oil and gas recovery operations. In cases where the impacts would be small and primarily the result of construction activities, operational controls could be proposed. No definitive reduction in emissions can be made at this point, however, since operational controls have not been used as mitigation measures in the past. Also, it is not clear whether the use of operational strategies would satisfy the applicable regulations or would be enforceable, especially at the local level.

Technological controls deemed to be feasible for mitigating potential impacts from Sale No. 53 are outlined in Table VII-5. Emissions reductions are presented for each major emission source and for the Lease Sale as a whole. Some of the technological control measures have not, at the present time, been fully demonstrated for use in offshore applications; some would be subject to economic or additional regulatory constraints. However, it is assumed that by the time peak construction and production activities are underway (mid- to late-1980s), these measures could be employed. There is no intent here to propose or recommend controls, only to catalogue possible options.

1. Projected Impacts and Proposed Mitigation Measures

a. Eel River Zone

i. Inert Pollutant Analysis

In modeling the impacts of both production- and construction-related

Table VII-5. POTENTIAL OCS LEASE SALE NO. 53 DAILY EMISSION REDUCTIONS BASED ON PROPOSED MITIGATION MEASURES[1]

Emission Source	Pollutants of Concern[2] (Percent of Total Lease Sale No. 53 Emissions)	Potential Mitigation Measures	Estimated Percent Emission Reductions[3]
1. Production Platform	HC(9), NO_x(35), SO_x(30), CO(50), TSP(45)		
Activity	Major Pollutants (Percent of Platform Emissions)		
Power Generation	NO_x(92), SO_x(92), CO(92), TSP(94)	Use of natural gas as fuel Waste heat utilization Water injection in turbines	NO_x(60), SO_x(95), CO(10), TSP(40)
Development Drilling	NO_x(8), SO_x(8), CO(8)	Waste heat utilization Water injection in turbines	NO_x(50), SO_x(10), CO(10)
Evaporative (fugitive) Losses	HC(100)	Proper Operation and Maintenance	HC(75)
		PERCENT OF OCS LEASE SALE 53 EMISSIONS REDUCED BY MITIGATION OF PLATFORM EMISSIONS	HC(07), NO_x(21), SO_x(26), CO(04), TSP(17)
2. OSRI (with tankers)	HC(57), NO_x(51), SO_x(57), TSP(22)		
Activity	Major Pollutants (Percent of OSRI Emissions)		
Gas Processing	HC(60), SO_x(24)	Vapor recovery Proper Operation and Maintenance	HC(95), SO_x(75)
Tankers Loading	HC(30), SO_x(23)	Vapor balance line Use of low sulfur fuel	HC(90), SO_x(75)
Tankers In Sea Passage	SO_x(40)	Use of low sulfur fuel	SO_x(75)
		PERCENT OF OCS LEASE SALE NO. 53 EMISSIONS REDUCED BY MITIGATION OF OSRI EMISSIONS	HC(52), SO_x(34)
3. Onshore Gas Processing Plant	HC(34), NO_x(9), SO_x(17)		
Activity	Major Pollutants (Percent of Gas Processing Emissions)		
Storage Tanks	HC(< 1)	Installation of floating roofs	
Oil Processing	HC(< 1), NO_x(12)	Waste heat utilization	
Gas Processing	HC(> 99), NO_x(88), SO_x(100)	Proper operation & maintenance Vapor recovery Waste heat utilization (eliminate direct-fired heaters)	HC(90), NO_x(90), SO_x(75)
		PERCENT OF OCS LEASE SALE NO. 53 EMISSIONS REDUCED BY MITIGATION OF GAS PROCESSING PLANT EMISSIONS	HC(31), NO_x(08), SO_x(13)
4. Support Activity (boats, barges)	NO_x(51), CO(47), TSP(31)	Catalytic reactor, exhaust Gas recirculation, fuel injection retard	NO_x(70), CO(-), TSP(-)
		PERCENT OF OCS LEASE SALE NO. 53 EMISSIONS REDUCED BY MITIGATION OF SUPPORT ACTIVITY EMISSIONS	NO_x(36), CO(-), TSP(-)
		TOTAL PROJECTED OCS LEASE SALE NO. 53 EMISSIONS REDUCTIONS	HC(90), NO_x(65), SO_x(73), CO(04), TSP(17)

1. Emission sources and the percent of OCS Lease Sale No. 53 emissions that result from these sources are based on maximum daily emissions estimates for the Santa Maria zone as presented in Table V-51 (Chapter V). The table is purposely general and is intended to present an overall indication of the relative Lease Sale No. 53 percent emissions reductions that could be achieved given application of the proposed mitigation measures.

2. For each major source (i.e. production platform, OSRI with tankers...) the relative percent of OCS Lease Sale No. 53 emissions they represent are presented. Under each major source are the specific operations (and the percent of emissions that contribute to emissions from the major source).

3. Estimated percent emission reductions for Lease Sale No. 53 are presented for each specific operation listed under each major source, for the major source as a whole and overall for OCS Lease Sale No. 53.

emissions, a worst case scenario was developed based on very limited meteorological data. It also assumed that all sources would be located at a single point, an event that is not likely to occur. By attempting to be highly conservative, the results could overestimate the onshore impact of emissions from development within the Eel River zone by a factor of 6 to 8.

According to the air emissions inventory (Chapter V), nitrogen oxides would be emitted in the highest quantity in 1985, the year of peak construction activity. The principal sources would be diesel-fired engines used to power tugboats and the derrick barges (needed during platform installation). The modeling of these activities indicates a potential annual onshore nitrogen dioxide increment of 2.9 $\mu g/m^3$, well below the National Ambient Air Quality Standard (NAAQS). However, assuming DOI's proposed significance levels are adopted (see Table VI-2), the onshore nitrogen oxide increment would exceed the significance level by 1.9 $\mu g/m^3$. It should be emphasized that: 1) the model overestimates the predicted changes in air quality; 2) the sources of nitrogen oxides are primarily associated with the temporary use of construction related equipment; and 3) the probability of the worst case actually happening would be very low. Although BACT is expected to be required, based upon the reading of the proposed DOI regulations, it would appear that operational strategies involving scheduling and location modifications of vessel activities could be practical, alternative control measures.

Worst case emissions and modeling assumptions used in the short-term pollutant analyses could result in rather large onshore NO_2 concentration increments (i.e., 248 $\mu g/m^3$ compared to the California three-hour standard of 470 $\mu g/m^3$). Since the proposed DOI significance levels do not incorporate a short-term nitrogen dioxide increment, it is not clear whether mitigating measures would be required. However, it is unlikely that all point sources would congregate as a single point source. In addition, the very low probability of worst-case conditions and the fact that highest emission levels would be the result of temporary construction activities, suggest that mitigation proposed as a result of the modeled annual increments could reduce short-term nitrogen dioxide onshore increments.

Sulfur oxides would be emitted in the highest quantity in 1987, the year of peak production. Diesel-fired turbines (for power generation) would be the primary pollution source. The second largest source would be associated with gas processing. This is of special concern because, under Transportation Scenario 1A, the processing facility could be onshore. As in the case of nitrogen oxides, the worst case situation modeled is extremely conservative and should overestimate the more typical emissions by a substantial factor. Therefore, though the modeling results predict an increase of 1.1 $\mu g/m^3$ of sulfur dioxide, which marginally exceeds the proposed significance level, the sulfur dioxide emissions from offshore facilities probably would not require mitigation. However, if mitigating measures were required, the use of lower sulfur fuel, which could involve switching to gas, would reduce sulfur dioxide increments to below the DOI significance levels.

There would appear to be reasonable cause for concern over the potential for sulfur oxide emissions from any proposed onshore gas processing plants in the North Coast Air Basin because emissions from stationary onshore sources have been predicted to increase by about 76 percent by 1995 (North Coast County Air Pollution Control Council, 1977). A proposed onshore gas processing plant would have to comply with either PSD or nonattainment provisions depending on

sulfur dioxide designation status in the North Coast Air Basin at the time of construction. Results of the modeling effort forecast a maximum impact of nearly 13 $\mu g/m^3$ sulfur dioxide. This would be a substantial fraction of the PSD limit of 20 $\mu g/m^3$. The use of scrubbers and/or emission offsets, if required, could meet regulatory requirements. If not, then siting of gas processing activities on the platform could substantially reduce any onshore impacts.

The largest quantities of particulate matter would be emitted in 1985, the year of maximum construction. Almost as much particulate matter would be produced in 1987, the year of maximum production. The principal source in 1985 would be diesel engines (powering the barges and tugboats needed to install a platform and pipeline). In 1987, diesel turbines would be operating and generating power for all production related activities. On an annual basis, particulate matter onshore increments would represent only a fraction of the DOI significance level -- 0.14 $\mu g/m^3$ out of an allowable 1 $\mu g/m^3$, and therefore would not require mitigation. It should be noted, however, that the air quality in the area already exceeds the state and federal annual standards. The estimated short term onshore increment for particulate matter would exceed the DOI significance level of 5 $\mu g/m^3$ by 1 $\mu g/m^3$. However, the modeling assumed a 12 hour constant activity level for the boats and barges associated with temporary construction work. This is extremely conservative. A more realistic activity level would have given modeled increments below DOI's proposed levels. Since air quality standards for TSP in the North Coast Air Basin are exceeded during periods of strong atmospheric inversions and subsequent air stagnation, vessel scheduling and location modifications might be considered as mitigation measures for the mobile sources associated with temporary construction activities.

Carbon monoxide would be emitted in the largest quantities in 1985, the year of maximum construction. The major sources would be diesel engines providing power for the barges and tugboats needed for pipeline and platform installation. The estimated maximum onshore increment (43 $\mu g/m^3$) under a worst case modeling approach would not result in any violation of federal or state ambient air quality standards (the most stringent standard is 10,000 $\mu g/m^3$). Given the DOI 1-hour and 8-hour significance levels of 2,000 and 500 $\mu g/m^3$, respectively, mitigation measures for the control of carbon monoxide emissions would not be required.

ii. Reactive Pollutant Analysis

a) Routine Emissions

Hydrocarbons would be emitted in the greatest quantities in 1987, the year of peak production. The major source of hydrocarbons would be gas processing. This would be particularly important because of the proposal to consider both offshore and onshore locations for the processing facility. Nitrogen oxide emissions are expected to be quite large in 1987, although not as great as in 1985. Nitrogen oxides would be associated with diesel fuel combustion emissions, both by turbines on the platform and supply boats moving between shore and the platform.

Modeling the projected impact of these emissions was complicated by the lack of valid meteorological and air quality data. If worst case meteorology and emissions were to occur, the ozone concentration onshore could increase by

50 percent above the 1987 forecast baseline. Such an increase would not result in a violation of either the federal or state standards for oxidant.

Under the proposed DOI regulations, volatile organic compounds emitted within 36 hours travel time of an attainment area would have to be controlled by BACT. This requirement would apply to sources of hydrocarbons associated with OCS development of the Eel River zone. Hydrocarbon emissions from offshore activities (primarily gas processing) could be reduced by approximately 90 percent by measures outlined in Table VII-5.

b) Accident Emissions

The worst case accident at the platform modeled was a blowout of 10 million cubic feet per day. Emissions occurring in the early morning hours from such an accident could result in onshore oxidant concentrations of up to 0.20 ppm, in violation of all ambient air quality standards. The probability of such an occurrence in the Eel River zone is very low. Potential mitigation measures for control of accidents would include best design, construction and operation of platform and OS&T facilities.

b. Point Arena Zone

i. Inert Pollutant Analysis

In modeling the impact of pollutants emitted in the Point Arena zone, a worst case set of meteorological and source parameters was used. Such conservatism results in a worst case with a very low probability of ever happening. This approach also means the impact of any emissions can be overestimated by as much as an order of magnitude.

As indicated in the air emissions inventory (Chapter V), nitrogen oxides would be emitted in the greatest quantity in 1989, the year of peak production. The principal sources would be diesel turbines used for power generation offshore and diesel engines used to power supply boats shuttling between the production site and the onshore base.

Even with the projected overestimation of results, the modeling of these activities indicates that neither the NO_2 AAQS or DOI's proposed $1 \mu g/m^3$ significance level would be exceeded.

The short-term modeling analysis indicated a maximum potential 1-hour NO_2 onshore increment of 283 $\mu g/m^3$ given the many worst case assumptions and simplifications incorporated in the modeling approach. Since DOI has not proposed a short-term NO_2 significance level, it is not clear whether this increment would require mitigation. However, operational controls involving vessel scheduling modifications both in terms of time of day and with respect to air quality conditions could be considered.

Sulfur oxides would also be emitted in the highest quantity in 1989. The principal sources would all be related to the combustion of diesel fuel -- tankers and supply boats in transit between the production area and San Francisco, and gas processing and turbines used for power generation at the platforms. The gas processing plant could be onshore, so the expected impact of its emissions is of particular concern. Even using conservative worst case

assumptions, the projected short-term and annual onshore sulfur dioxide concentration increments from offshore sources would represent only about one percent of state and federal ambient air quality standards. However, under these worst case assumptions, the projected annual and 24-hour SO_2 onshore increments would marginally exceed DOI's proposed significance levels (by 0.1 and 1 $\mu g/m^3$, respectively). If mitigation measures are required, the use of lower sulfur fuel, either liquid or gas, could reduce worst case onshore increments to below the proposed significance levels.

In the case of an onshore gas processing plant (Transportation Scenario 1A), modeled sulfur dioxide concentration increments could represent 12 percent of the annual standards and 65 percent of the allowed annual average PSD Class II increment. Depending on permit requirements for construction, the use of scrubbers similar to those used in current onshore processing facilities might be indicated. It is expected that such a mitigation measure would reduce onshore sulfur dioxide concentrations to acceptable levels. If not, emission offsets might then be necessary.

Particulate matter would be emitted in the largest quantities in 1989. The main sources would be diesel engines on boats and diesel-fired turbines used for power generation on the platform. The contribution to ambient particulate levels from activities in the Point Arena zone is expected to be small and well below the proposed DOI significance level, i.e., 0.13 $\mu g/m^3$ out of an allowed 1 $\mu g/m^3$.

Carbon monoxide would be emitted in the largest quantity in 1987, as a product of combustion. Diesel-fired engines on supply boats and diesel-fired turbines generating power on the platform would be the major sources. Maximum emission impacts of 43 $\mu g/m^3$, under a worst case modeling approach, would not be expected to result in any violation of federal or state ambient air quality standards. Since the smallest increment of the DOI significance level proposed for carbon monoxide is the 8-hour 500 $\mu g/m^3$ limit, no mitigation measures would be required.

ii. Reactive Pollutant Analysis

a) Routine Emissions

Hydrocarbons would be emitted in the greatest quantities in 1989, the year of peak production. The major sources of hydrocarbon would be tankers loading and gas processing.

The modeling of the projected impacts from the combination of hydrocarbon and nitrogen oxide emissions was complicated by the lack of valid meteorological and air quality data. If the worst case meteorology and emissions were to occur at the same time (an unlikely event), the ozone concentration onshore could increase by nearly 50 percent above the projected 1989 baseline. Such an increase would cause the California oxidant standards, but not the NAAQS to be violated. Thus, according to DOI's proposed 36-hour travel time requirement for volatile organic compounds being transported into an attainment area, BACT would be the mitigation measure required. Based on Table VII-5, suggested mitigation measures for hydrocarbon emissions associated with gas processing and tanker loading are available which could reduce volatile organic compound emissions by 90 percent.

b) Accident Emissions

The worst case accident at the platform modeled was a blowout of 1,000 barrels per day. Emissions occurring in the early morning hours from such an accident could result in onshore oxidant concentrations of up to 0.20 ppm, a violation of all ambient air quality standards. The probability of such an occurrence in the Point Arena zone is quite low. The best possible design, construction and operation of the platforms, OS&T's and associated facilities would serve as preventive measures against blowouts and spills and would therefore be the most effective mitigation measures.

c. Bodega Zone

i. Inert Pollutant Analysis

In order to model a worst case emissions episode, all sources were located at a single point three miles from shore. Worst case meteorological data were available from a monitoring station on the San Francisco peninsula. The conservative approach used in modeling onshore impacts could result in an overestimation of the impact.

Nitrogen oxides would be emitted at the maximum level in 1985, the year of peak construction activity. The two largest sources would be diesel engines on the tugboats and derrick barge involved with platform installation, both of which are temporary sources. The Gaussian modeling technique used to compute annual concentration increments indicates a potential NO_2 onshore increment of 4.4 $\mu g/m^3$, above the DOI proposed sigificance level of 1 $\mu g/m^3$. However, since construction activity would likely be further than three miles from shore (the closest onshore point from the east edge of the zone is 10 miles), the proposed significance level would probably not be exceeded, and mitigation measures would not be required.

The short-term nitrogen dioxide modeling suggests that under worst-case meteorological conditions, all mobile sources clumped as a single point source could result in onshore nitrogen dioxide increments of approximately 40 percent of the California one-hour standard. The distance to the maximum nitrogen dioxide impact was estimated to be approximately three miles. Again, since the closest onshore point from the east edge of the tract would be well over 10 miles away, it is anticipated that the one-hour nitrogen dioxide increment would be significantly reduced by the time the plume hits the shoreline.

Sulfur oxide emissions would be at the maximum level in 1987, the year of maximum production. Sulfur oxides would be associated with combustion processes; thus, the largest source would be diesel-fired turbines used for power generation at the platform. Diesel engines in boats would produce only about onethird as much sulfur oxides as the turbines. The modeled annual and short-term impacts are very small and would not exceed the DOI proposed significance levels. Therefore, mitigation measures would not be required.

Particulate matter would be emitted at the highest levels in 1985. The derrick barge and the tugboats used to support platform installation are expected to be the two major sources of particulate matter. The onshore impacts of the additional particulate matter emissions would be low (0.3 percent of the federal annual primary standard and 23 percent of the proposed 1 $\mu g/m^3$ DOI significance

level). Given that platform construction would take place at least 10 miles offshore and would involve mobile sources (modeling assumed all emission sources clumped at a single point three miles offshore), it is expected that annual concentration increments would be actually much lower onshore.

Projected short-term particulate matter onshore increments estimated by the Gaussian model PTMTP are approximately 6 $\mu g/m^3$ at a distance of three miles. This increment would exceed DOI's proposed significance level of 5 $\mu g/m^3$. However, since the mobile emission sources used would be clustered primarily around the offshore platform(s) located at least 10 miles offshore, the expected onshore particulate matter increment would be significantly reduced and mitigation measures would probably not be required.

Carbon monoxide would also be emitted at peak levels in 1987. Platform installation and supply boats operating between the work site and San Francisco would be the two activities with sources emitting substantial amounts of carbon monoxide. The onshore impact as modeled would be negligible (15 $\mu g/m^3$ compared to the allowed 500 $\mu g/m^3$ increment under the proposed DOI regulations). Therefore, mitigation measures would probably not be required.

ii. Reactive Pollutant Analysis

a) Routine Emissions

The highest level of hydrocarbon emissions are projected to occur in 1987, the peak production year. The major source of hydrocarbons would be loading tankers or barges. Nitrogen oxide emissions would be only slightly less than in 1985. Nitrogen oxides are combustion products, and would come primarily from supply boats traveling between San Francisco and the production area.

Modeling the projected impact of the combination of hydrocarbon and nitrogen oxide emissions utilized actual meteorological and air quality data from the Bay Area Air Quality Management District. Conservatively assuming that all emitting sources would be located at a single point results in an overestimation of the onshore impact. Because actual historical data were input to the model, the worst case meteorology does have a reasonable probability of occurring, and the pollutants could reach the San Francisco area within 36 hours. Of the four trajectories modeled (Bay Area Trajectories 3, 4, 5 and 7), two were projected to result in an onshore impact of 1 pphm oxidant. This increase in the ambient air concentration would be sufficient in the case of Trajectory 5 (see Chapter VI) to cause the NAAQS to be exceeded. Since the modeling indicates that volatile organic compounds would be emitted within a 36-hour travel time of a nonattainment area for ozone, the proposed DOI regulations would require that all volatile organic compound emissions be reduced or offset. Therefore, the suggested hydrocarbon mitigation measures, such as are given in Table VII-5, would be warranted. Emission offsets in the San Francisco Bay Area could also be required.

b) Accident Emissions

The modeled worst case accident at the platform was a blowout of 1,000 barrels per day. Emissions occurring in the early morning hours from such an accident could result in onshore oxidant concentrations of up to 0.13 ppm, in violation of all ambient air quality standards. The probability of such an

occurrence in the Bodega zone is quite low. Mitigation would be primarily based on proper design, construction and operation of the oil and gas development facilities.

d. Santa Cruz

i. Inert Pollutant Analysis

Nitrogen oxides would be emitted in the greatest quantity in 1988, the year of peak construction. Diesel engines on the derrick barge and on tugboats associated with the installation of two platforms would be the largest emission sources.

Because the location of the emission sources cannot be predicted at this time, a reasonable distribution throughout the zone was estimated. Even with the modeling results being intentionally conservative, the estimated onshore maximum annual increment of 1 $\mu g/m^3$ would not result in a violation of the federal annual ambient air quality standard. Since this worst case value equals rather than exceeds the DOI proposed significance level for NO_2, mitigation would probably not be required. An onshore gas processing facility could increase the estimated annual onshore NO_2 increment by 7.4 $\mu g/m^3$. Although EPA has not determined PSD significance levels for NO_2 at the present time, it is expected that any proposed onshore gas processing plant associated with Lease Sale No. 53 would have to comply with a future PSD increment for NO_2.

The nitrogen oxide short-term (one hour) modeling analysis indicates a potential onshore nitrogen dioxide increment of 283 $\mu g/m^3$. This compares with the California state standard of 470 $\mu g/m^3$. DOI has not proposed a short-term significance level for nitrogen dioxide. However, given that the modeling approach used simplifications and worst case assumptions which overestimate the onshore impact of development in the Santa Cruz zone, any mitigation of the nitrogen oxides emitted from the mobile sources associated with platform construction would probably be operational in nature. Measures involving vessel schedule and locational modifications would be possible options.

Sulfur oxides would be emitted in the highest quantity in 1990, the year of maximum production. The largest stationary sources would be gas processing operations and the diesel-fired turbines providing offshore power. If Transportation Scenario 3 were adopted, tankers burning two percent sulfur residual oil would be a significant source of sulfur oxide emissions. Even under worst case modeling assumptions the hourly and annual onshore impact of additional sulfur oxides from offshore development within the Santa Cruz zone would be minimal and would not exceed DOI proposed significance levels.

The construction of an onshore gas processing plant adjacent to the Santa Cruz zone could increase annual ambient sulfur dioxide levels by an estimated 11.9 $\mu g/m^3$. This increase would represent a substantial fraction (60 percent) of the annual PSD Class II increment. Since preconstruction review of any proposed onshore gas processing facility would be handled by the local air pollution control district, the use of mitigation measures such as scrubbers or emissions trade-offs, would be evaluated and prescribed at that time to ensure compliance with the specific regulations for new sources locating in the area.

Under Scenario 1A, a projected onshore gas processing plant could raise the sulfur dioxide content of the ambient air by as much as 26 $\mu g/m^3$ 500 meters from the facility. Since this value would exceed the PSD limits for a Class II area it is possible that such mitigation measures as are presented in Table VII-5 may not be sufficient to meet PSD requirements. In this case, emission offsets might then have to be employed. If emission requirements are still not met, it is expected that the facility would not be granted a permit to construct. In addition, short-term hydrogen sulfide concentration increments could, under worst case conditions, potentially result in violations of the California one-hour standard. An onshore gas processing plant would require the approval of the local APCD and mitigation measures would probably be required. Fugitive losses are expected to be the major source of hydrogen sulfide emissions; hence, proper operation and maintenance practices would be the major control technique to be considered.

Particulate matter would be emitted in the greatest quantity in 1989 as a product of diesel fuel combustion in the engines of supply boats, tugboats and barges and in turbines providing power at the platforms. The impact of these additional particulates would be minimal (10 percent of the DOI proposed annual significance level). Therefore, mitigation of particulate matter emissions would probably not be required. It should be noted, however, that the state and federal (secondary) annual standards are currently exceeded in both San Luis Obispo and Santa Barbara counties. Given worst case modeling assumptions, and the probable overestimation of results, operational controls would probably be the most appropriate measures if mitigation were required.

A worst case modeling assumption of continuous vessel operations over a 12-hour period could result in a 24-hour average onshore particulate matter increment of 5 $\mu g/m^3$, equal to the proposed DOI significance level. Since the modeled increment does not exceed the proposed DOI significance level and since the nature of the model combined with the worst case assumptions likely overestimates onshore increments, mitigation of short-term particulate matter increments does not appear necessary.

Carbon monoxide would also be emitted in the greatest quantity in 1989. The derrick barges and tugboats used to install the platform and the diesel-fired turbines on production platforms would be the primary emission sources. The onshore impact of an additional 46 $\mu g/m^3$, according to the modeling results, would be minimal when compared to the DOI proposed significance level of 500 $\mu g/m^3$. Therefore, mitigation of carbon monoxide emissions would not appear to be necessary.

ii. Reactive Pollutant Analysis

a) Routine Emissions

Hydrocarbons would be emitted in greatest quantities in 1991. The major sources would be loading tankers and gas processing. Nitrogen oxides would be nearly as high as in 1989. The sources would still be combustion equipment--diesel engines on supply and crew boats and diesel-fired turbines at the production site.

Modeling the projected impact of the combination of hydrocarbons and nitrogen oxides utilized air quality data from both San Luis Obispo and Santa Barbara counties and meteorological data from Point Arguello. Four trajectories

were traced across the area. The projected future baselines at Nipomo, Santa Maria and Santa Ynez would exceed the California oxidant standards. The value expected at Nipomo would also exceed the NAAQS for ozone. The added increments resulting from Lease Sale No. 53 development could cause the NAAQS to be equalled or exceeded for the Nipomo and Santa Ynez trajectories. The fourth trajectory leading through Goleta would be the only one initially below all air quality standards. The projected onshore incremental increases range from 1 pphm in Goleta to 2.5 pphm in Nipomo. Since federal ozone standards have been exceeded in Santa Barbara and state ozone standards have been violated in both Santa Barbara and San Luis Obispo counties, and hydrocarbon emissions from the Santa Maria zone could reach either county within 36 hours, it would be necessary to reduce or offset all volatile organic compound emissions to comply with the current proposed DOI regulations. The use of vapor balance or recovery systems could reduce hydrocarbon emissions by 90 percent (see Table VII-5). Emissions offsets would also likely still be required for the remaining emissions.

b) Accident Emissions

The two most severe accidents modeled were a 1,000 bbl/day blowout and a 10,000 bbl spill. Depending upon the meteorological conditions at the time of such an accident, the oxidant levels onshore could increase by as much as 4 pphm. The California oxidant standard would be exceeded at Goleta and both California and NAAQS could be exceeded at Nipomo, Santa Maria or Santa Ynez. Given these potential impacts, it is imperative that the best possible design, construction and operation of the platforms, OS&T's and associated facilities be utilized.

F. Summary and Conclusions

Potential mitigation measures for projected Sale No. 53 air quality impacts were based on a general review of all measures that could be considered feasible for mitigation of either present or future OCS activities. Some of the measures described have not yet been fully demonstrated as useable in offshore applications; some would be subject to additional regulatory constraints. However, it is assumed that by the time peak construction and production operations are under way (mid to late 1980s), these measures could be employed.

Each of the five development zones in Sale No. 53 was examined individually to project the most appropriate technological and/or operational mitigation measures for each pollutant predicted by the modeling results to have a significant onshore impact (as determined under the applicable regulations). Given the modeling results, all zones would require mitigation of hydrocarbon emissions based on DOI's proposed 36-hour upper limit for volatile organic compound travel time to shore. The degree of control would depend on the attainment status of the affected onshore area. Offshore sources of nitrogen oxides, sulfur dioxide and particulate matter could also require mitigation in some of the zones since the proposed DOI significance levels were projected to be marginally exceeded. Sulfur dioxide and particulate matter emissions from onshore gas processing plants hypothesized under Scenario 1A could require mitigation measures in order to be granted construction permits by the local APCD.

With implementation of the control measures projected for Sale No. 53 onshore air impacts (Table VII-5), hydrocarbon emissions associated with platform operations, tanker/barge loading and gas processing could be reduced by 90 percent. In order to comply with more stringent DOI proposed regulations

for ozone nonattainment areas, however, the additional estimated 10 percent of hydrocarbon emissions remaining may have to be offset in the San Francisco Bay Area Air Basin, North Central Coast Air Basin, and South Central Coast Air Basin, since all three contain nonattainment areas for ozone.

Nitrogen oxide emissions from diesel-fired turbines and engines could be reduced by approximately 60 to 70 percent if suggested control techniques were applied to both stationary and mobile sources. Locating gas processing facilities offshore rather than onshore could reduce the short-term onshore impact of sulfur dioxide and particulate matter emissions without the need for any additional control measures. Requiring lower sulfur fuel in any particular type of combustion equipment could be an effective mitigating measure for offshore activities. Since the modeling analysis showed that under worst case assumptions, onshore increments of nitrogen dioxide, sulfur dioxide and particulate matter would in most areas only marginally exceed the DOI proposed significance levels, the above measures should be effective in reducing onshore increments to below the prescribed limiting values.

In addition to describing potential mitigation measures and percent emission reductions estimated for each measure, Table VII-5 estimates the projected reduction in overall Sale No. 53 emissions after application of the possible mitigation measures. Enforceability of these measures is assumed to have been adequately provided for in the applicable regulations. DOI approval of OCS exploration and development and production plans would require evidence that all relevant conditions of the draft regulations would be met. Granting of construction permits for onshore sources by the local APCDs would require similar evidence of mitigation.

In conclusion, it appears that OCS air quality impacts could be mitigated sufficiently to comply with the applicable regulations, given that the recommended control technologies would be developed and approved for use by the mid 1980s, and that onshore hydrocarbon offsets would be available in order to comply with DOI's strict requirements for ozone nonattainment areas. However, since final DOI regulations have not been promulgated, it is difficult to state with certainty what kinds of measures would actually be required for OCS Lease Sale No. 53. In addition, further clarification of the proposed DOI regulations would be helpful, especially in light of the proposed requirement for reducing <u>all</u> volatile organic compounds emitted within a 36-hour travel time of an ozone nonattainment area. Emission offsets would more than likely be required in three of the four air basins adjacent to Lease Sale No. 53 zones in order to comply with this provision, but these offsets might be difficult to obtain. Also, it would not be unexpected to find substantive differences of opinion about exemptions in the interpretation of the proposed rules. For example, there does not appear to be a specific definition of the "activities" which may be included in the article exempting from "further regulatory review: (i) Activities with uncontrolled emissions of each air pollutant of under 100 tons per year; or (ii) Activities with controlled emissions of each air pollutant of under 50 tons per year. (44 FR 27457)." Finally, the proposed DOI regulations do not set significance levels that parallel some of the state standards for the particular pollutants. For example, no short-term NO_2 significance level is proposed which, under worst-case conditions, could lead to a large increase in the onshore NO_2 ambient concentration. Promulgation of final DOI regulations should clarify the existing uncertainties for mitigation of Sale No. 53 projected air impacts.

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APPENDIX A

AIR EMISSIONS INVENTORY

SUPPORTING DATA

OFFSHORE/ONSHORE PRODUCTION AND DEVELOPMENT, AND PIPELINE-RELATED EMISSIONS DATA

Table A-1. EMISSION FACTORS FOR LEASE SALE NO. 53 OCS EXPLORATION, PRODUCTION, AND SUPPORT ACTIVITY

Activity/Source	Units	Emission Factor						Reference
		HC	NO_x	SO_x	CO	TSP	H_2S	
EXPLORATORY PHASE								
Drilling Power-Diesel Fired Reciprocation Engines	g/hp-hr	0.43	12.9	0.87	1.89	Neg.	--	Aerotherm Inc. (1976-Draft)
Supply and Crew Boats	lbs/10^3 gal fuel	13	572	39	86	25	--	Goodley et al. (1976)
Vehicular	lbs/vehicle-mile	0.002	0.004	0.0002	0.037	0.0007	--	SCAQMD (1977)
Helicopter	lbs/landing-takeoff/engine	0.52	0.57	0.18	5.7	0.25	--	EPA AP-42 (1973)
DEVELOPMENT PHASE								
Platform Installation								
Tug, Supply and Crew Boats	lbs/10^3 gal fuel	13	572	39	86	25	--	Goodley et al. (1976)
Derrick Barge	lbs/10^3 gal fuel	34.7	494	31.1	94.2	30.1	--	EPA AP-42 (1975)
Pipeline Installation								
Tug, Supply and Crew Boats	lbs/10^3 gal fuel	13	572	39	86	25	--	Goodley et al. (1976)
Lay Barge	lbs/10^3 gal fuel	34.7	494	31.1	94.2	30.1	--	EPA AP-42 (1975)
Jet Barge	lbs/10^3 gal fuel	34.7	494	31.1	94.2	30.1	--	EPA AP-42 (1975)

Table A-1 (continued)

Activity/Source	Units	Emission Factor HC	NO_x	SO_x	CO	TSP	H_2S	Reference
Overland Pipeline Construction								
Sidebooms and Bulldozers	lbs/KWH	0.0017	0.037	0.0026	0.0054	0.0012	--	EPA AP-42 (1977)
Backhoe	lbs/KWH	0.0030	0.0437	0.0028	0.0083	0.0027	--	EPA AP-42 (1977)
Welding Equipment, Joint Pot	lbs/hp-hr	0.0025	0.0309	0.0021	0.0067	0.0022	--	EPA AP-42 (1977)
Trucks (Medium Duty)	lbs/vehicle-mile	0.0101	0.0461	0.0062	0.0633	0.0029	--	EPA AP-42 (1977)
Trucks (Pickup)	lbs/vehicle-mile	0.0088	0.0098	--	0.1194	--	--	EPA AP-42 (1977)
PRODUCTION PHASE								
Power Generation-Diesel Fired Turbines	g/hp-hr	0.14	1.65	0.87	0.38	0.12	--	EPA AP-42 (1975)
Natural Gas Combustion-Heat Treating and Gas Dehydration	$lbs/10^8\ ft^3$	8	100	0.6	20	10	--	EPA AP-42 (1974)
Gas Processing	$lbs/10^8\ ft^3$	210	10	10.6	--	--	2.6	Leach *et al*. (1975)
Evaporative Losses:								
Wastewater Separators	$lbs/10^3$ bbl	10	--	--	--	--	--	EPA AP-42, Suppl. 8 (1978)
Pump Seals	$lbs/10^3$ bbl	17	--	--	--	--	--	EPA AP-42, Suppl. 8 (1979)
Compressor Seals	$lbs/10^3$ bbl	4	--	--	--	--	--	C.E. Burklin *et al*., (1976)
Relief Valves	$lbs/10^3$ bbl	11	--	--	--	--	--	EPA AP-42, Suppl. 8 (1978)
Pipeline Valves and Flanges	$lbs/10^3$ bbl	28	--	--	--	--	--	EPA AP-42, Suppl. 8 (1978)

Table A-2. SCENARIO OF INSTALLED POWER DISTRIBUTION[1]

Requirement	Condition		
	Drilling	Tripping Casing, Coring	Logs
Draw Works	0	1,600	0
Mud Pumps	2,100	0	0
Rotary	800	0	0
Accessories	400	200	200
Housekeeping	100	100	100
TOTAL	3,400	1,900	300

Source: Energy Resources Co. (1977).

1. These values are assumed to be "typical" and have been used in this report to estimate potential rates of emission.

Table A-3. POWER GENERATION, INSTALLED CAPACITY AND ESTIMATED USAGE REQUIRED FOR OFFSHORE PRODUCTION/DEVELOPMENT FACILITIES[1]

Gas Compression[2]		Electricity Generation[3]		Water Injection	
Capacity ($hp/10^6CFD$)	Usage ($hp\text{-}hr/10^6cf$)	Capacity ($hp/10^3BOD$)	Usage ($hp\text{-}hr/10^3bbl$)	Capacity ($hp/10^3BOD$)	Usage ($hp\text{-}hr/10^3bbl$)
300	6,100	250	5,300	150	3,000

1. Source: Energy Resources Company (1977).

2. Includes requirements for gas lift, gathering, and send-out.

3. Includes oil pumping and miscellaneous services, also includes power for fixed platforms. It is assumed that 40 percent of total is for oil pumping.

Table A-4. DRILLING SCENARIO - EEL RIVER ZONE

A. Exploratory Drilling[1] (Basis: 6,000 ft well)

Activity	Days	Usage Factor (%)	Power (hp)	Usage (hp-hr)
Drilling	21	25	3,400	428,400
Coring	2	50	1,900	45,600
Casing	4	50	1,900	91,200
Surveys & Logs	2	80	300	11,520
	29			576,720

B. Delineation Drilling[1] (Basis: 5,500 ft well)

Activity	Days	Usage Factor (%)	Power (hp)	Usage (hp-hr)
Drilling	20	25	3,400	408,000
Coring	2	50	1,900	45,600
Casing	3	50	1,900	68,400
Surveys & Logs	2	80	300	11,520
	27			533,520

C. Development Drilling[1] (Basis: 5,500 ft well)

Activity	Days	Usage Factor (%)	Power (hp)	Usage (hp-hr)
Drilling	17	25	3,400	346,800
Coring	2	50	1,900	45,600
Casing	3	50	1,900	68,400
Surveys & Logs	1	80	300	5,760
	23			466,560

1. Based on well depth and drilling time supplied in USGS Lease Sale No. 53 drilling scenario, and power and usage factors from Energy Resources Co. (1977).

Table A-5. MAXIMUM DAILY EMISSIONS ASSOCIATED WITH PRELIMINARY DRILLING - EEL RIVER ZONE

Source	Emissions (lbs/day/well)				
	HC	NO_x	SO_x	CO	TSP
A. Exploratory Drilling					
Power for Drilling[1]	19	565	38	83	Neg.
Support Activities					
Supply Boat[2]	7	294	44	20	13
Crew Boat[3]	1	40	3	6	2
Helicopter[4]	6	7	2	68	3
Vehicular[5]	1	2	—	23	—
	34	908	87	200	18
B. Delineation Drilling					
Power for Drilling[1]	19	561	38	82	Neg.
Support Activities					
Supply Boat[2]	7	294	44	20	13
Crew Boat[3]	1	40	3	6	2
Helicopter[4]	6	7	2	68	3
Vehicular[5]	1	2	—	23	—
	34	904	87	199	18

1. Based on the emission factors for diesel-fired reciprocating engines presented in Table A-1. Refer to Table A-4 for a summary of the drilling scenarios.

2. Based on the emission factors presented in Table A-1. Assumes 35 miles/round trip (between the drilling site and Eureka) with 2 trips/day. Based on an average speed of 13 knots and a fuel consumption rate of 110 gal/hr.

3. Based on the emission factors presented in Table A-1. Assumes 35 miles/round trip (between the drilling site and Eureka) with 2 trips/day. Based on an average speed of 17 knots and a fuel consumption rate of 20 gal/hr.

4. Based on the emission factors presented in Table A-1. Assumes 2 engines/helicopter with 4 landing-takeoff (LTO) cycles daily onshore and 2 LTO cycles daily on the platform.

5. Based on the emission factors presented in Table A-1. Assumes 20 miles/vehicle/day with 31 personnel or 620 vehicle-miles traveled/day.

Table A-6. MAXIMUM DAILY PLATFORM INSTALLATION EMISSIONS - EEL RIVER ZONE

Source	Emissions (lbs/day/platform)				
	HC	NO_x	SO_x	CO	TSP
Derrick Barge[1]	115	1,645	103[7]	314	100
Tugboats[2]	75	3,294	224[8]	495	144
Supply Boat[3]	7	294	20[8]	44	13
Crew Boat[4]	1	40	3[8]	6	2
Helicopter[5]	6	7	2[9]	68	3
Vehicular[6]	5	10	neg.	92	2
	209	5,290	352	1,019	264

1. Based on the emission factors presented in Table A-1 and a fuel consumption rate of 3,300 gal/day.

2. Based on the emission factors presented in Table A-1. Assumes 4 tugboats working simultaneously with a fuel consumption rate of 75 gal/hr/tugboat. An 80 percent usage factor has been assumed.

3. Based on the emission factors presented in Table A-1. Assumes 35 miles/round trip and 2 trips/day. Based on fuel consumption rate of 110 gal/hr.

4. Based on the emission factors presented in Table A-1. Assumes 35 miles/round trip with 2 trips/day. Based on a fuel consumption rate of 20 gal/hr.

5. Based on the emission factors presented in Table A-1. Assumes 2 engines/helicopter with 4 landing-takeoff (LTO) cycles daily onshore and 2 LTO cycles on the platform.

6. Based on the emission factors presented in Table A-1. Assumes 20 miles/vehicle/day with 125 personnel or 2,500 vehicle-miles traveled/day.

7. Assumes 0.22 percent sulfur fuel.

8. Assumes 0.275 percent sulfur fuel.

9. Assumes 0.05 percent sulfur fuel.

Table A-7. MAXIMUM DAILY PIPELINE INSTALLATION EMISSIONS - EEL RIVER ZONE

Source	Emissions (lbs/day)				
	HC	NO_x	SO_x	CO	TSP
Tugboats[1]	94	4,118	281[9]	619	180
Lay Barge[2]	59	840	53[8]	160	52
Jet Barge[3]	208	2,965	187[8]	565	183
Supply Boat[4]	7	294	20[9]	44	13
Crew Boat[5]	1	40	3[9]	6	2
Helicopter[6]	6	7	2[10]	68	3
Vehicular[7]	12	24	1	222	4
	387	8,298	547	1,684	437

1. Based on emission factors presented in Table A-1. Assumes 4 tugs working simultaneously. Based on fuel consumption of 75 gal/hr/tug.

2. Based on emission factors presented in Table A-1. Assumes fuel consumption of 1,700 gal/day.

3. Based on emission factors presented in Table A-1. Assumes fuel consumption of 6,000 gal/day. Pipeline would be buried in water depths of less than 250 ft.

4. Based on the emission factors in Table A-1. Assumes 35 miles/round trip with 2 trips/day. Based on average speed of 13 knots and fuel consumption rate of 110 gal/hr.

5. Based on the emission factors presented in Table A-1. Assumes 35 miles/round trip with 2 trips/day. Based on average speed of 17 knots and fuel consumption rate of 20 gal/hr.

6. Based on the emission factors presented in Table A-1. Assumes 2 engines/helicopter with 4 landing-takeoff (LTO) cycles on shore and 2 LTO cycles at the installation site.

7. Based on emission factors presented in Table A-1. Assumes 300 personnel and 20 miles/trip/day or 6,000 vehicle-miles traveled/day.

8. Assumes 0.22 percent sulfur fuel.

9. Assumes 0.275 percent sulfur fuel

10. Assumes 0.05 percent sulfur fuel.

Table A-8. DAILY EMISSIONS FROM DEVELOPMENT DRILLING - EEL RIVER ZONE

Pollutant	Emissions (lb/day/well)[1]
HC	6
NO_x	74
SO_x	39
CO	17
TSP	5

1. Based on the emission factors for diesel fired turbines presented in Table A-1. Refer to Table A-4 for a summary of the drilling scenario.

Table A-9. DEVELOPMENT SUPPORT EMISSIONS - EEL RIVER ZONE

Source	Emissions (lbs/day/platform)[1]				
	HC	NO_x	SO_x	CO	TSP
Supply Boat[2]	10	441	30	66	19
Crew Boat[3]	2	80	5	12	4
Helicopter[4]	6	7	2	68	3
Vehicular[5]	8	16	1	148	3
	26	544	38	294	29

1. Emissions/platform would be reduced 5 percent for each additional drilling platform to account for increased efficiency in transporting supplies and crews.

2. Based on the emission factors presented in Table A-1. Assumes 35 miles/round trip with 3 boats making 1 round trip/day. Based on an average speed of 13 knots and a fuel consumption rate of 110 gal/hr.

3. Based on the emission factors presented in Table A-1. Assumes 35 miles/round trip with 4 trips/day. Based on an average speed of 17 knots and a fuel consumption rate of 20 gal/hr.

4. Based on the emission factors presented in Table A-1. Assumes 2 engines/helicopter with 4 landing-takeoff (LTO) cycles daily onshore and 2 LTO cycles daily on the platform.

5. Based on the emission factors presented in Table A-1. Assumes 20 miles/vehicle/day with 200 personnel or 4000 vehicle-miles traveled/day.

Table A-10. PRODUCTION SUPPORT EMISSIONS - EEL RIVER ZONE
(BASIS: 3 PLATFORMS)

Source	Emissions (lbs/day)				
	HC	NO_x	SO_x	CO	TSP
Supply Boat[1]	3	147	10	22	6
Crew Boat[2]	—	20	1	3	1
Helicopter[3]	2	2	1	23	1
Vehicular[4]	2	5	Neg.	44	1
	7	174	12	92	9

1. Based on the emission factors presented in Table A-1. Assumes 1 supply boat/3 platforms and one 35 mile round trip/day/supply boat. Based on an average speed of 13 knots and a fuel consumption rate of 110 gal/hr.

2. Based on the emission factors presented in Table A-1. Assumes 1 crew boat/ 4 platforms and one 35 mile round trip/day/crewboat. Based on an average speed of 17 knots and a fuel consumption rate of 20 gal/hr.

3. Based on the emission factors presented in Table A-1. Assumes 1 helicopter/ 4 platforms with 2 landing-takeoff (LTO) cycles daily onshore and 1 LTO cycle daily on the platform. Helicopters were assumed to have 2 engines.

4. Based on the emission factors presented in Table A-1. Assumes 20 miles/ vehicle/day with 20 personnel/platform or 1,200 vehicle-miles traveled/day.

Table A-11. DRILLING SCENARIO - POINT ARENA ZONE

A. Exploratory Drilling[1] (Basis: 8,000 ft well)

Activity	Days	Usage Factor (%)	Power (hp)	Usage (hp-hr)
Drilling	27	25	3,400	550,800
Coring	3	50	1,900	68,400
Casing	5	50	1,900	114,000
Surveys & Logs	2	80	300	11,500
	37			744,700

B. Delineation Drilling[1] (Basis: 6,500 ft well)

Activity	Days	Usage Factor (%)	Power (hp)	Usage (hp-hr)
Drilling	21	25	3,400	428,400
Coring	2	50	1,900	45,600
Casing	4	50	1,900	91,200
Surveys & Logs	2	80	300	11,520
	29			576,720

C. Development Drilling[1] (Basis: 5,000 ft well)

Activity	Days	Usage Factor (%)	Power (hp)	Usage (hp-hr)
Drilling	16	25	3,400	326,400
Coring	2	50	1,900	45,600
Casing	3	50	1,900	68,400
Surveys & Logs	1	80	300	5,760
	22			446,160

1. Based on well depth and drilling time supplied in USGS Lease Sale No. 53 drilling scenario, and power and usage factors from Energy Resources Co. (1977).

Table A-12. MAXIMUM DAILY EMISSIONS ASSOCIATED WITH PRELIMINARY DRILLING - POINT ARENA ZONE

Source	Emissions (lbs/day/well)				
	HC	NO_x	SO_x	CO	TSP
A. Exploratory Drilling					
Power for Drilling[1]	19	571	38	84	Neg.
Support Activities					
Supply Boat[2]	65	2,852	194	429	125
Crew Boat[3]	1	34	2	5	1
Helicopter[4]	6	7	2	68	3
Vehicular[5]	1	2	—	23	—
	92	3,466	236	609	129
B. Delineation Drilling					
Power for Drilling[1]	20	592	40	87	Neg.
Support Activities					
Supply Boat[2]	65	2,852	194	429	125
Crew Boat[3]	1	34	2	6	1
Helicopter[4]	6	7	2	68	3
Vehicular[5]	1	2	—	23	—
	93	3,487	238	612	129

1. Based on the emission factors for diesel-fired reciprocating engines presented in Table A-1. Refer to Table A-11 for a summary of the drilling scenarios.

2. Based on the emission factors presented in Table A-1. Assumes 340 miles/round trip (between the drilling site and the San Francisco Bay Area) with 2 trips/day. Based on an average speed of 13 knots and a fuel consumption rate of 110 gal/hr.

3. Based on the emission factors presented in Table A-1. Assumes 30 miles/round trip (between the drilling site and the nearest port) with 2 trips/day. Based on an average speed of 17 knots and a fuel consumption rate of 20 gal/hr.

4. Based on the emission factors presented in Table A-1. Assumes 2 engines/helicopter with 4 landing-takeoff (LTO) cycles daily onshore and 2 LTO cycles daily on the platform.

5. Based on the emission factors presented in Table A-1. Assumes 20 miles/vehicle/day with 31 personnel or 620 vehicle-miles traveled/day.

Particulate matter would be emitted in the greatest quantity in 1988, primarily from the use of diesel fuel in the engines of supply boats, tugboats and barges. A realistic modeling distribution of emission sources within the Santa Cruz zone would result in estimated annual onshore increments of 0.07 $\mu g/m^3$, well below the 1 $\mu g/m^3$ significance level proposed by DOI. On a short-term basis, however, the emissions from the mobile sources associated with platform construction and development could equal the DOI proposed 24-hour significance level of 5 $\mu g/m^3$ for particulate matter. However, given the temporary and mobile nature of the emission sources and the fact that DOI's significance levels would probably not be exceeded, mitigation measures are not expected to be required.

Carbon monoxide would also be emitted (from the derrick barges and tugboats used to install the platforms) in the greatest quantity in 1988. The onshore impact of an additional estimated 45 $\mu g/m^3$, would be negligible in the North Central Coast area. The DOI proposed significance level for 8-hour average carbon monoxide is 500 $\mu g/m^3$. No mitigation measures are apparently necessary for the control of carbon monoxide emissions.

ii. Reactive Pollutant Analysis

a) Routine Emissions

Hydrocarbons would be emitted in greatest quantities in 1990. The major sources would be tanker loading and gas processing. Nitrogen oxides would be nearly as high as in 1988. The sources would still be combustion equipment--diesel engines on supply and crew boats and diesel-fired turbines at the production site.

The three modeled, projected baseline values for the San Francisco Bay Area (Trajectories 1, 2 and 6) all exceeded the California oxidant standard; two exceeded the NAAQS. Adding the small incremental change (less than 1 pphm) produced by development activities in the Santa Cruz zone could cause the NAAQS standards to be equaled or exceeded in all cases. A trajectory into Scotts Valley in Santa Cruz County, examined because current oxidant levels exceed air quality standards, indicated that development would not have any appreciable effect on the expected ozone concentration there. The projected oxidant values in Salinas and Monterey are expected to be well within all state and federal standards. Even at the low level of 3 and 4 pphm, Lease Sale No. 53 development would not have a significant impact along the trajectories described for the Monterey peninsula.

Regardless that projected ozone increments are less than 1 pphm, mitigation measures would still be required because of existing and projected violations of state and federal ozone standards and because hydrocarbons emitted from the Santa Cruz area could be expected to impact within 36 hours upon any of the areas just mentioned. Mitigation measures as outlined in Table VII-5 for platforms and activities along Bay Area Trajectories 1, 2 and 6 could reduce hydrocarbon emissions in the range of 90 percent. Onshore ozone increments could be substantially reduced as a result of reducing offshore emissions. Emissions offsets in any of the three air basins, San Francisco Bay Area, North Central Coast, or South Central Coast, potentially subject to effects from Sale No. 53 development could be required in order to reduce all emissions as stipulated by the proposed DOI regulations.

b) Accident Emissions

A blowout of 1,000 bbls/day could result in an additional 2 pphm and a large spill of 10,000 bbls could result in an additional 0.05 pphm. If either of these were to occur at such a time that pollutants were transported to the San Francisco area, or towards Scotts Valley, all oxidant air quality standards would be exceeded. Strict adherence to best design, construction and operation procedures for platform and OS&T facilities would reduce the likelihood of accidents.

e. Santa Maria Zone

i. Inert Pollutant Analysis

Air quality data used to model emissions from the Santa Maria zone were available for input to the models from both San Luis Obispo and Santa Barbara counties. A reasonable spatial distribution of activities through the entire zone was assumed.

Nitrogen oxides are expected to be emitted in the greatest quantity in 1989, the year of peak construction. Diesel engines on the derrick barge and on tugboats working to install two platforms are estimated to be the largest emission sources. Because of the total number of platforms to be built, their construction could go on at various locations within the zone for five years. Modeling results based on intentionally conservative assumptions indicate a possible onshore increment of 1.5 $\mu g/m^3$ for nitrogen dioxide. Although the above increment would not be expected to result in any violations of the NAAQS, it would marginally exceed the 1 $\mu g/m^3$ significance level as proposed by DOI and therefore would require mitigation. Control measures as proposed by the DOI for temporary activities on the OCS would fall under the category of BACT. Although BACT would ultimately be determined on a case-by-case basis, it could include such nitrogen oxide reduction methods as the use of catalytic reactors (although not presently demonstrated for diesel engines), exhaust gas recirculation or fuel injection retard. These methods could substantially reduce projected onshore nitrogen oxide increments. However, the use of operational controls if technological measures could also be considered.

Short-term nitrogen dioxide increments based on the modeling assumption that all mobile sources associated with platform and pipeline construction are clumped at a single point source located at the three-mile limit could be as much as 60 percent of the California hourly standard of 470 $\mu g/m^3$. However, given the conservative modeling approach, the lack of a short-term DOI significance level for NO_2, and the possible use of BACT or operational controls as described for annual nitrogen dioxide increments, no added mitigation requirements would likely be expected.

Sulfur oxides would be emitted in the highest quantity in 1991, the year of maximum production. The largest stationary sources would be gas processing equipment and the diesel-fired turbines providing the offshore power. If Transportation Scenarios 2 or 3 were adopted, the tankers in transit and loading at the OS&T would also be major sources. Under the conservative worst case modeled, the onshore impact of an additional 0.7 $\mu g/m^3$ would not be significant based on the proposed DOI regulations. Therefore mitigation of sulfur oxide emissions as a result of offshore activities would probably not be required.

Table A-13. MAXIMUM DAILY PLATFORM INSTALLATION EMISSIONS - POINT ARENA ZONE

Source	Emissions (lbs/day/platform)				
	HC	NO_x	SO_x	CO	TSP
Derrick Barge[1]	115	1,645	103[7]	314	100
Tugboats[2]	75	3,294	224[8]	495	144
Supply Boat[3]	65	2,852	1,948[8]	429	125
Crew Boat[4]	1	34	2[8]	5	1
Helicopter[5]	6	7	2[9]	68	3
Vehicular[6]	5	10	Neg.	92	2
	267	7,842	525	1,403	375

1. Based on the emission factors presented in Table A-1 and a fuel consumption rate of 3,300 gal/day.

2. Based on the emission factors presented in Table A-1. Assumes 4 tugboats working simultaneously with a fuel consumption rate of 75 gal/hr/tugboat. An 80 percent usage factor has been assumed.

3. Based on the emission factors presented in Table A-1. Assumes 340 miles/round trip and 2 trips/day. Based on fuel consumption rate of 110 gal/hr.

4. Based on the emission factors presented in Table A-1. Assumes 40 miles/round trip with 2 trips/day. Based on a fuel consumption rate of 20 gal/hr.

5. Based on the emission factors presented in Table A-1. Assumes 2 engines/helicopter with 4 landing-takeoff (LTO) cycles daily onshore and 2 LTO cycles on the platform.

6. Based on the emission factors presented in Table A-1. Assumes 20 miles/vehicle/day with 125 personnel or 2,500 vehicle-miles traveled/day.

7. Assumes 0.22 percent sulfur fuel.

8. Assumes 0.275 percent sulfur fuel.

9. Assumes 0.05 percent sulfur fuel.

Table A-14. MAXIMUM DAILY PIPELINE INSTALLATION EMISSIONS - POINT ARENA ZONE

Source	Emissions (lbs/day)				
	HC	NO_x	SO_x	CO	TSP
Tugboats[1]	94	4,118	281[9]	619	180
Lay Barge[2]	59	840	53[8]	160	52
Jet Barge[3]	208	2,965	187[8]	565	183
Supply Boat[4]	65	2,852	194[9]	429	125
Crew Boat[5]	1	34	2[9]	5	1
Helicopter[6]	6	7	2[10]	68	3
Vehicular[7]	12	24	1	222	4
	445	10,840	720	2,068	548

1. Based on emission factors presented in Table A-1. Assumes 4 tugs working simultaneously. Based on fuel consumption of 75 gal/hr/tug.

2. Based on emission factors presented in Table A-1. Assumes fuel consumption of 1,700 gal/day.

3. Based on emission factors presented in Table A-1. Assumes fuel consumption of 6,000 gal/day. Pipeline would be buried in water depths of less than 250 ft.

4. Based on the emission factors in Table A-1. Assumes 340 miles/round trip with 2 trips/day. Based on average speed of 13 knots and fuel consumption rate of 110 gal/hr.

5. Based on the emission factors presented in Table A-1. Assumes 30 miles/round trip with 2 trips/day. Based on average speed of 17 knots and fuel consumption rate of 20 gal/hr.

6. Based on the emission factors presented in Table A-1. Assumes 2 engines/helicopter with 4 landing-takeoff (LTO) cycles on shore and 2 LTO cycles at the installation site.

7. Based on emission factors presented in Table A-1. Assumes 300 personnel and 20 miles/trip/day or 6,000 vehicle-miles traveled/day.

8. Assumes 0.22 percent sulfur fuel.

9. Assumes 0.275 percent sulfur fuel

10. Assumes 0.05 percent sulfur fuel.

Table A-15. DAILY EMISSIONS FROM DEVELOPMENT DRILLING - POINT ARENA ZONE

Pollutant	Emissions (lb/day/well)[1]
HC	6
NO_x	74
SO_x	39
CO	16
TSP	5

1. Based on the emission factors for diesel fired turbines presented in Table A-1. Refer to Table A-11 for a summary of the drilling scenario.

Table A-16. DEVELOPMENT SUPPORT EMISSIONS - POINT ARENA ZONE

Source	Emissions (lbs/day/platform)[1]				
	HC	NO_x	SO_x	CO	TSP
Supply Boat[2]	97	4,279	292	643	187
Crew Boat[3]	2	69	5	10	3
Helicopter[4]	6	7	2	68	3
Vehicular[5]	8	16	1	148	3
	113	4,471	300	869	196

1. Emissions/platform would be reduced 5 percent for each additional drilling platform to account for increased efficiency in transporting supplies and crews.

2. Based on the emission factors presented in Table A-1. Assumes 340 miles/round trip with 3 boats making 1 round trip/day. Based on an average speed of 13 knots and a fuel consumption rate of 110 gal/hr.

3. Based on the emission factors presented in Table A-1. Assumes 30 miles/round trip with 4 trips/day. Based on an average speed of 17 knots and a fuel consumption rate of 20 gal/hr.

4. Based on the emission factors presented in Table A-1. Assumes 2 engines/helicopter with 4 landing-takeoff (LTO) cycles daily onshore and 2 LTO cycles daily on the platform.

5. Based on the emission factors presented in Table A-1. Assumes 20 miles/vehicle/day with 200 personnel or 4000 vehicle-miles traveled/day.

Table A-17. PRODUCTION SUPPORT EMISSIONS - POINT ARENA ZONE
(BASIS: 5 PLATFORMS)

Source	Emissions (lbs/day)				
	HC	NO_x	SO_x	CO	TSP
Supply Boat[1]	68	2,856	193	431	125
Crew Boat[2]	1	34	2	5	1
Helicopter[3]	2	2	1	23	1
Vehicular[4]	4	8	—	74	1
	75	2,900	196	533	128

1. Based on the emission factors presented in Table A-1. Assumes 1 supply boat/3 platforms and one 340 mile round trip/day/supply boat. Based on an average speed of 13 knots and a fuel consumption rate of 110 gal/hr.

2. Based on the emission factors presented in Table A-1. Assumes 1 crew boat/5 platforms and two 30 mile round trip/day/crewboat. Based on an average speed of 17 knots and a fuel consumption rate of 20 gal/hr.

3. Based on the emission factors presented in Table A-1. Assumes 1 helicopter/4 platforms with 2 landing-takeoff (LTO) cycles daily onshore and 1 LTO cycle daily on the platform. Helicopters were assumed to have 2 engines.

4. Based on the emission factors presented in Table A-1. Assumes 20 miles/vehicle/day with 20 personnel/platform or 2,000 vehicle-miles traveled/day.

Table A-18. DRILLING SCENARIO - BODEGA ZONE

A. Exploratory Drilling[1] (Basis: 7,000 ft well)

Activity	Days	Usage Factor (%)	Power (hp)	Usage (hp-hr)
Drilling	19	25	3,400	387,600
Coring	2	50	1,900	45,600
Casing	3	50	1,900	68,400
Surveys & Logs	2	80	300	11,520
	26			513,120

B. Delineation Drilling[1] (Basis: 6,000 ft well)

Activity	Days	Usage Factor (%)	Power (hp)	Usage (hp-hr)
Drilling	16	25	3,400	326,400
Coring	2	50	1,900	45,600
Casing	3	50	1,900	68,400
Surveys & Logs	1	80	300	5,760
	22			446,160

C. Development Drilling[1] (Basis: 5,000 ft well)

Activity	Days	Usage Factor (%)	Power (hp)	Usage (hp-hr)
Drilling	11	25	3,400	224,400
Coring	2	50	1,900	45,600
Casing	2	50	1,900	45,600
Surveys & Logs	1	80	300	5,760
	16			321,360

1. Based on well depth and drilling time supplied in USGS Lease Sale No. 53 drilling scenario, and power and usage factors from Energy Resources Co. (1977).

Table A-19. MAXIMUM DAILY EMISSIONS ASSOCIATED WITH PRELIMINARY DRILLING - BODEGA ZONE

Source	Emissions (lbs/day/well)				
	HC	NO_x	SO_x	CO	TSP
A. Exploratory Drilling					
Power for Drilling[1]	19	568	38	83	Neg.
Support Activities					
Supply Boat[2]	20	840	58	125	38
Crew Boat[3]	1	46	3	7	2
Helicopter[4]	6	7	2	68	3
Vehicular[5]	1	2	—	23	—
	47	1,463	101	306	43
B. Delineation Drilling					
Power for Drilling[1]	19	568	38	83	Neg.
Support Activities					
Supply Boat[2]	20	840	58	125	38
Crew Boat[3]	1	46	3	7	2
Helicopter[4]	6	7	2	68	3
Vehicular[5]	1	2	—	23	—
	47	1,463	101	306	43

1. Based on the emission factors for diesel-fired reciprocating engines presented in Table A-1. Refer to Table A-18 for a summary of the drilling scenarios.

2. Based on the emission factors presented in Table A-1. Assumes 100 miles/round trip (between the drilling site and the San Francisco Bay Area) with 2 trips/day. Based on an average speed of 13 knots and a fuel consumption rate of 110 gal/hr.

3. Based on the emission factors presented in Table A-1. Assumes 40 miles/round trip (between the drilling site and the nearest port) with 2 trips/day. Based on an average speed of 17 knots and a fuel consumption rate of 20 gal/hr.

4. Based on the emission factors presented in Table A-1. Assumes 2 engines/helicopter with 4 landing-takeoff (LTO) cycles daily onshore and 2 LTO cycles daily on the platform.

5. Based on the emission factors presented in Table A-1. Assumes 20 miles/vehicle/day with 31 personnel or 620 vehicle-miles traveled/day.

Table A-20. MAXIMUM DAILY PLATFORM INSTALLATION EMISSIONS - BODEGA ZONE

Source	Emissions (lbs/day/platform)				
	HC	NO_x	SO_x	CO	TSP
Derrick Barge[1]	115	1,645	103[7]	314	100
Tugboats[2]	75	3,294	224[8]	495	144
Supply Boat[3]	19	839	57[8]	126	37
Crew Boat[4]	1	45	3[8]	7	1
Helicopter[5]	6	7	2[9]	68	3
Vehicular[6]	5	10	Neg.	92	2
	221	5,840	389	1,102	287

1. Based on the emission factors presented in Table A-1 and a fuel consumption rate of 3,300 gal/day.

2. Based on the emission factors presented in Table A-1. Assumes 4 tugboats working simultaneously with a fuel consumption rate of 75 gal/hr/tugboat. An 80 percent usage factor has been assumed.

3. Based on the emission factors presented in Table A-1. Assumes 100 miles/round trip and 2 trips/day. Based on fuel consumption rate of 110 gal/hr.

4. Based on the emission factors presented in Table A-1. Assumes 40 miles/round trip with 2 trips/day. Based on a fuel consumption rate of 20 gal/hr.

5. Based on the emission factors presented in Table A-1. Assumes 2 engines/helicopter with 4 landing-takeoff (LTO) cycles daily onshore and 2 LTO cycles on the platform.

6. Based on the emission factors presented in Table A-1. Assumes 20 miles/vehicle/day with 125 personnel or 2,500 vehicle-miles traveled/day.

7. Assumes 0.22 percent sulfur fuel.

8. Assumes 0.275 percent sulfur fuel.

9. Assumes 0.05 percent sulfur fuel.

Table A-21. MAXIMUM DAILY PIPELINE INSTALLATION EMISSIONS - BODEGA ZONE[1]

Source	Emissions (lbs/day)				
	HC	NO_x	SO_x	CO	TSP
Tugboats[2]	94	4,118	281[9]	619	180
Lay Barge[3]	59	840	53[8]	160	52
Supply Boat[4]	20	839	57[9]	126	37
Crew Boat[5]	1	45	3[9]	7	1
Helicopter[6]	6	7	2[10]	68	3
Vehicular[7]	12	24	1	222	4
	192	5,873	397	1,202	277

1. Pipeline is gathering system only and will not be buried.

2. Based on emission factors presented in Table A-1. Assumes 4 tugs working simultaneously. Based on fuel consumption of 75 gal/hr/tug.

3. Based on emission factors presented in Table A-1. Assumes fuel consumption of 1,700 gal/day.

4. Based on the emission factors in Table A-1. Assumes 100 miles/round trip with 2 trips/day. Based on average speed of 13 knots and fuel consumption rate of 110 gal/hr.

5. Based on the emission factors presented in Table A-1. Assumes 40 miles/round trip with 2 trips/day. Based on average speed of 17 knots and fuel consumption rate of 20 gal/hr.

6. Based on the emission factors presented in Table A-1. Assumes 2 engines/helicopter with 4 landing-takeoff (LTO) cycles on shore and 2 LTO cycles at the installation site.

7. Based on emission factors presented in Table A-1. Assumes 300 personnel and 20 miles/trip/day or 6,000 vehicle-miles traveled/day.

8. Assumes 0.22 percent sulfur fuel.

9. Assumes 0.275 percent sulfur fuel

10. Assumes 0.05 percent sulfur fuel

Table A-22. DAILY EMISSIONS FROM DEVELOPMENT DRILLING - BODEGA ZONE

Pollutant	Emissions (lb/day/well)[1]
HC	6
NO_x	68
SO_x	36
CO	16
TSP	5

1. Based on the emission factors for diesel fired turbines presented in Table A-1. Refer to Table A-18 for a summary of the drilling scenario.

Table A-23. DEVELOPMENT SUPPORT EMISSIONS - BODEGA ZONE

Source	Emissions (lbs/day/platform)[1]				
	HC	NO_x	SO_x	CO	TSP
Supply Boat[2]	29	1,259	87	189	55
Crew Boat[3]	2	92	6	14	4
Helicopter[4]	6	7	2	68	3
Vehicular[5]	8	16	1	148	3
	45	1,374	96	419	65

1. Emissions/platform would be reduced 5 percent for each additional drilling platform to account for increased efficiency in transporting supplies and crews.

2. Based on the emission factors presented in Table A-1. Assumes 100 miles/round trip with 3 boats making 1 round trip/day. Based on an average speed of 13 knots and a fuel consumption rate of 110 gal/hr.

3. Based on the emission factors presented in Table A-1. Assumes 40 miles/round trip with 4 trips/day. Based on an average speed of 17 knots and a fuel consumption rate of 20 gal/hr.

4. Based on the emission factors presented in Table A-1. Assumes 2 engines/helicopter with 4 landing-takeoff (LTO) cycles daily onshore and 2 LTO cycles daily on the platform.

5. Based on the emission factors presented in Table A-1. Assumes 20 miles/vehicle/day with 200 personnel or 4000 vehicle-miles traveled/day.

Table A-24. PRODUCTION SUPPORT EMISSIONS - BODEGA ZONE
(BASIS: 3 PLATFORMS)

Source	Emissions (lbs/day)				
	HC	NO_x	SO_x	CO	TSP
Supply Boat[1]	10	420	29	63	19
Crew Boat[2]	1	23	2	4	1
Helicopter[3]	2	2	2	23	2
Vehicular[4]	2	5	—	44	1
	15	450	32	133	23

1. Based on the emission factors presented in Table A-1. Assumes 1 supply boat/3 platforms and one 100 mile round trip/day/supply boat. Based on an average speed of 13 knots and a fuel consumption rate of 110 gal/hr.

2. Based on the emission factors presented in Table A-1. Assumes 1 crew boat/ 4 platforms and one 40 mile round trip/day/crewboat. Based on an average speed of 17 knots and a fuel consumption rate of 20 gal/hr.

3. Based on the emission factors presented in Table A-1. Assumes 1 helicopter/ 4 platforms with 2 landing-takeoff (LTO) cycles daily onshore and 1 LTO cycle daily on the platform. Helicopters were assumed to have 2 engines.

4. Based on the emission factors presented in Table A-1. Assumes 20 miles/ vehicle/day with 20 personnel/platform or 3,200 vehicle-miles traveled/day.

Table A-25. DRILLING SCENARIO - SANTA CRUZ ZONE

A. Exploratory Drilling[1] (Basis: 7,000 ft well)

Activity	Days	Usage Factor (%)	Power (hp)	Usage (hp-hr)
Drilling	24	25	3,400	489,600
Coring	2	50	1,900	45,600
Casing	5	50	1,900	114,000
Surveys & Logs	2	80	300	11,500
	33			660,700

B. Delineation Drilling[1] (Basis: 6,500 ft well)

Activity	Days	Usage Factor (%)	Power (hp)	Usage (hp-hr)
Drilling	21	25	3,400	428,400
Coring	2	50	1,900	45,600
Casing	4	50	1,900	91,200
Surveys & Logs	2	80	300	11,500
	29			576,700

C. Development Drilling[1] (Basis: 4,500 ft well)

Activity	Days	Usage Factor (%)	Power (hp)	Usage (hp-hr)
Drilling	16	25	3,400	326,400
Coring	2	50	1,900	45,600
Casing	3	50	1,900	68,400
Surveys & Logs	1	80	300	5,760
	22			446,160

1. Based on well depth and drilling time supplied in USGS Lease Sale No. 53 drilling scenario, and power and usage factors from Energy Resources Co. (1977).

Table A-26. DAILY EMISSIONS ASSOCIATED WITH PRELIMINARY DRILLING - SANTA CRUZ ZONE

Source	Emissions (lbs/day/well)				
	HC	NO_x	SO_x	CO	TSP
A. Exploratory Drilling					
Power for Drilling[1]	19	567	38	83	Neg.
Support Activities					
Supply Boat[2]	16	672	46	100	30
Crew Boat[3]	1	46	3	7	2
Helicopter[4]	6	7	2	68	3
Vehicular[5]	1	2	—	23	—
	43	1,294	89	281	35
B. Delineation Drilling					
Power for Drilling[1]	19	567	38	83	Neg.
Support Activities					
Supply Boat[2]	16	672	46	100	30
Crew Boat[3]	1	46	3	7	2
Helicopter[4]	6	7	2	68	3
Vehicular[5]	1	2	—	23	—
	43	1,294	89	281	35

1. Based on the emission factors for diesel-fired reciprocating engines presented in Table A-1. Refer to Table A-25 for a summary of the drilling scenarios.

2. Based on the emission factors presented in Table A-1. Assumes 80 miles/round trip (between the drilling site and the San Francisco Bay Area) with 2 trips/day. Based on an average speed of 13 knots and a fuel consumption rate of 110 gal/hr.

3. Based on the emission factors presented in Table A-1. Assumes 40 miles/round trip (between the drilling site and the nearest port) with 2 trips/day. Based on an average speed of 17 knots and a fuel consumption rate of 20 gal/hr.

4. Based on the emission factors presented in Table A-1. Assumes 2 engines/helicopter with 4 landing-takeoff (LTO) cycles daily onshore and 2 LTO cycles daily on the platform.

5. Based on the emission factors presented in Table A-1. Assumes 20 miles/vehicle/day with 31 personnel or 620 vehicle-miles traveled/day.

Table A-27. MAXIMUM DAILY PLATFORM INSTALLATION EMISSIONS - SANTA CRUZ ZONE

Source	Emissions (lbs/day/platform)				
	HC	NO_x	SO_x	CO	TSP
Derrick Barge[1]	115	1,645	103[7]	314	100
Tugboats[2]	75	3,294	224[8]	495	144
Supply Boat[3]	15	671	46[8]	101	29
Crew Boat[4]	1	45	3[8]	7	2
Helicopter[5]	6	7	2[9]	68	3
Vehicular[6]	5	10	Neg.	92	2
	217	5,672	388	1,077	279

1. Based on the emission factors presented in Table A-1 and a fuel consumption rate of 3,300 gal/day.

2. Based on the emission factors presented in Table A-1. Assumes 4 tugboats working simultaneously with a fuel consumption rate of 75 gal/hr/tugboat. An 80 percent usage factor has been assumed.

3. Based on the emission factors presented in Table A-1. Assumes 80 miles/round trip and 2 trips/day. Based on fuel consumption rate of 110 gal/hr.

4. Based on the emission factors presented in Table A-1. Assumes 40 miles/round trip with 2 trips/day. Based on a fuel consumption rate of 20 gal/hr.

5. Based on the emission factors presented in Table A-1. Assumes 2 engines/helicopter with 4 landing-takeoff (LTO) cycles daily onshore and 2 LTO cycles on the platform.

6. Based on the emission factors presented in Table A-1. Assumes 20 miles/vehicle/day with 125 personnel or 2,500 vehicle-miles traveled/day.

7. Assumes 0.22 percent sulfur fuel.

8. Assumes 0.275 percent sulfur fuel.

9. Assumes 0.05 percent sulfur fuel.

Table A-28. MAXIMUM DAILY PIPELINE INSTALLATION EMISSIONS - SANTA CRUZ ZONE

Source	Emissions (lbs/day)				
	HC	NO_x	SO_x	CO	TSP
Tugboats[1]	94	4,118	281[9]	619	180
Lay Barge[2]	59	840	53[8]	160	52
Jet Barge[3]	208	2,065	187[8]	565	183
Supply Boat[4]	15	671	46[9]	101	29
Crew Boat[5]	1	45	3[9]	7	1
Helicopter[6]	6	7	2[10]	68	3
Vehicular[7]	12	24	1	222	4
	396	8,670	573	1,742	452

1. Based on emission factors presented in Table A-1. Assumes 4 tugs working simultaneously. Based on fuel consumption of 75 gal/hr/tug.

2. Based on emission factors presented in Table A-1. Assumes fuel consumption of 1,700 gal/day.

3. Based on emission factors presented in Table A-1. Assumes fuel consumption of 6,000 gal/day. Pipeline would be buried in water depths of less than 250 feet.

4. Based on the emission factors in Table A-1. Assumes 80 miles/round trip with 2 trips/day. Based on average speed of 13 knots and fuel consumption rate of 110 gal/hr.

5. Based on the emission factors presented in Table A-1. Assumes 40 miles/round trip with 2 trips/day. Based on average speed of 17 knots and fuel consumption rate of 20 gal/hr.

6. Based on the emission factors presented in Table A-1. Assumes 2 engines/helicopter with 4 landing-takeoff (LTO) cycles on shore and 2 LTO cycles at the installation site.

7. Based on emission factors presented in Table A-1. Assumes 300 personnel and 20 miles/trip/day or 6,000 vehicle-miles traveled/day.

8. Assumes 0.22 percent sulfur fuel.

9. Assumes 0.275 percent sulfur fuel

10. Assumes 0.05 percent sulfur fuel.

Table A-29. DAILY EMISSIONS FROM DEVELOPMENT DRILLING - SANTA CRUZ ZONE

Pollutant	Emissions (lb/day/well)[1]
HC	6
NO_x	74
SO_x	39
CO	17
TSP	5

1. Based on the emission factors for diesel fired turbines presented in Table A-1. Refer to Table A-23 for a summary of the drilling scenario.

Table A-30. DEVELOPMENT SUPPORT EMISSIONS - SANTA CRUZ ZONE

Source	Emissions (lbs/day/platform)[1]				
	HC	NO_x	SO_x	CO	TSP
Supply Boat[2]	23	1,007	69	151	44
Crew Boat[3]	2	92	6	14	4
Helicopter[4]	6	7	2	68	3
Vehicular[5]	8	16	1	148	3
	39	1,122	78	381	54

1. Emissions/platform would be reduced 5 percent for each additional drilling platform to account for increased efficiency in transporting supplies and crews.

2. Based on the emission factors presented in Table A-1. Assumes 80 miles/round trip with 3 boats making 1 round trip/day. Based on an average speed of 13 knots and a fuel consumption rate of 110 gal/hr.

3. Based on the emission factors presented in Table A-1. Assumes 40 miles/round trip with 4 trips/day. Based on an average speed of 17 knots and a fuel consumption rate of 20 gal/hr.

4. Based on the emission factors presented in Table A-1. Assumes 2 engines/helicopter with 4 landing-takeoff (LTO) cycles daily onshore and 2 LTO cycles daily on the platform.

5. Based on the emission factors presented in Table A-1. Assumes 20 miles/vehicle/day with 200 personnel or 4000 vehicle-miles traveled/day.

Table A-31. PRODUCTION SUPPORT EMISSIONS - SANTA CRUZ ZONE
(BASIS: 8 PLATFORMS)

Source	Emissions (lbs/day)				
	HC	NO_x	SO_x	CO	TSP
Supply Boat[1]	23	1,007	69	151	44
Crew Boat[2]	1	46	3	7	2
Helicopter[3]	4	4	2	46	2
Vehicular[4]	6	13	1	118	2
	34	1,070	75	322	50

1. Based on the emission factors presented in Table A-1. Assumes 1 supply boat/3 platforms and one 80 mile round trip/day/supply boat. Based on an average speed of 13 knots and a fuel consumption rate of 110 gal/hr.

2. Based on the emission factors presented in Table A-1. Assumes 1 crew boat/4 platforms and one 30 mile round trip/day/crewboat. Based on an average speed of 17 knots and a fuel consumption rate of 20 gal/hr.

3. Based on the emission factors presented in Table A-1. Assumes 1 helicopter/4 platforms with 2 landing-takeoff (LTO) cycles daily onshore and 1 LTO cycle daily on the platform. Helicopters were assumed to have 2 engines.

4. Based on the emission factors presented in Table A-1. Assumes 20 miles/vehicle/day with 20 personnel/platform or 3,200 vehicle-miles traveled/day.

Table A-32. DRILLING SCENARIO - SANTA MARIA ZONE

A. Exploratory Drilling[1] (Basis: 5,000 ft well)

Activity	Days	Usage Factor (%)	Power (hp)	Usage (hp-hr)
Drilling	20	25	3,400	408,000
Coring	2	50	1,900	45,600
Casing	3	50	1,900	68,400
Surveys & Logs	2	80	300	11,520
	27			533,520

B. Delineation Drilling[1] (Basis: 4,500 ft well)

Activity	Days	Usage Factor (%)	Power (hp)	Usage (hp-hr)
Drilling	19	25	3,400	387,600
Coring	2	50	1,900	45,600
Casing	3	50	1,900	68,400
Surveys & Logs	2	80	300	11,520
	26			513,120

C. Development Drilling[1] (Basis: 4,000 ft well)

Activity	Days	Usage Factor (%)	Power (hp)	Usage (hp-hr)
Drilling	15	25	3,400	306,000
Coring	1	50	1,900	22,800
Casing	3	50	1,900	68,400
Surveys & Logs	1	80	300	5,760
	20			402,960

1. Based on well depth and drilling time supplied in USGS Lease Sale No. 53 drilling scenario, and power and usage factors from Energy Resources Co. (1977).

Table A-33. DAILY EMISSIONS ASSOCIATED WITH PRELIMINARY DRILLING - SANTA MARIA ZONE

Source	Emissions (lbs/day/well)				
	HC	NO_x	SO_x	CO	TSP
A. Exploratory Drilling					
Power for Drilling[1]	19	561	38	82	Neg.
Support Activities					
Supply Boat[2]	29	1,258	86	189	55
Crew Boat[3]	1	51	4	8	2
Helicopter[4]	6	7	2	68	3
Vehicular[5]	1	2	—	23	—
	56	1,879	130	370	60
B. Delineation Drilling					
Power for Drilling[1]	19	561	38	82	Neg.
Support Activities					
Supply Boat[2]	29	1,258	86	189	55
Crew Boat[3]	1	46	4	8	2
Helicopter[4]	6	7	2	68	3
Vehicular[5]	1	2	—	23	—
	56	1,879	130	370	60

1. Based on the emission factors for diesel-fired reciprocating engines presented in Table A-1. Refer to Table A-32 for a summary of the drilling scenarios.

2. Based on the emission factors presented in Table A-1. Assumes 150 miles/round trip (between the drilling site and Santa Barbara) with 2 trips/day. Based on an average speed of 13 knots and a fuel consumption rate of 110 gal/hr.

3. Based on the emission factors presented in Table A-1. Assumes 45 miles/round trip (between the drilling site and the nearest port) with 2 trips/day. Based on an average speed of 17 knots and a fuel consumption rate of 20 gal/hr.

4. Based on the emission factors presented in Table A-1. Assumes 2 engines/helicopter with 4 landing-takeoff (LTO) cycles daily onshore and 2 LTO cycles daily on the platform.

5. Based on the emission factors presented in Table A-1. Assumes 20 miles/vehicle/day with 31 personnel or 620 vehicle-miles traveled/day.

Table A-34. MAXIMUM DAILY PLATFORM INSTALLATION EMISSIONS - SANTA MARIA ZONE

Source	Emissions (lbs/day/platform)				
	HC	NO_x	SO_x	CO	TSP
Derrick Barge[1]	115	1,645	103[7]	314	100
Tugboats[2]	75	3,294	224[8]	495	144
Supply Boat[3]	30	1,258	86[8]	189	56
Crew Boat[4]	1	51	3[8]	8	1
Helicopter[5]	6	7	2[9]	68	3
Vehicular[6]	5	10	Neg.	92	2
	232	6,255	418	1,166	306

1. Based on the emission factors presented in Table A-1 and a fuel consumption rate of 3,300 gal/day.

2. Based on the emission factors presented in Table A-1. Assumes 4 tugboats working simultaneously with a fuel consumption rate of 75 gal/hr/tugboat. An 80 percent usage factor has been assumed.

3. Based on the emission factors presented in Table A-1. Assumes 150 miles/round trip and 2 trips/day. Based on fuel consumption rate of 110 gal/hr.

4. Based on the emission factors presented in Table A-1. Assumes 45 miles/round trip with 2 trips/day. Based on a fuel consumption rate of 20 gal/hr.

5. Based on the emission factors presented in Table A-1. Assumes 2 engines/helicopter with 4 landing-takeoff (LTO) cycles daily onshore and 2 LTO cycles on the platform.

6. Based on the emission factors presented in Table A-1. Assumes 20 miles/vehicle/day with 125 personnel or 2,500 vehicle-miles traveled/day.

7. Assumes 0.22 percent sulfur fuel.

8. Assumes 0.275 percent sulfur fuel.

9. Assumes 0.05 percent sulfur fuel.

Table A-35. MAXIMUM DAILY PIPELINE INSTALLATION EMISSIONS - SANTA MARIA ZONE

Source	Emissions (lbs/day)				
	HC	NO_x	SO_x	CO	TSP
Tugboats[1]	94	4,118	281[9]	619	180
Lay Barge[2]	59	840	53[8]	160	52
Jet Barge[3]	208	2,065	187[8]	565	183
Supply Boat[4]	30	1,258	86[9]	189	56
Crew Boat[5]	1	51	39[9]	8	1
Helicopter[6]	6	7	2[10]	68	3
Vehicular[7]	12	24	1	222	4
	410	9,263	616	1,831	479

1. Based on emission factors presented in Table A-1. Assumes 4 tugs working simultaneously. Based on fuel consumption of 75 gal/hr/tug.

2. Based on emission factors presented in Table A-1. Assumes fuel consumption of 1,700 gal/day.

3. Based on emission factors presented in Table A-1. Assumes fuel consumption of 6,000 gal/day. Pipeline would be buried in water depths of less than 250 feet.

4. Based on the emission factors in Table A-1. Assumes 150 miles/round trip with 2 trips/day. Based on average speed of 13 knots and fuel consumption rate of 110 gal/hr.

5. Based on the emission factors presented in Table A-1. Assumes 45 miles/round trip with 2 trips/day. Based on average speed of 17 knots and fuel consumption rate of 20 gal/hr.

6. Based on the emission factors presented in Table A-1. Assumes 2 engines/helicopter with 4 landing-takeoff (LTO) cycles on shore and 2 LTO cycles at the installation site.

7. Based on emission factors presented in Table A-1. Assumes 300 personnel and 20 miles/trip/day or 6,000 vehicle-miles traveled/day.

8. Assumes 0.22 percent sulfur fuel.

9. Assumes 0.275 percent sulfur fuel

10. Assumes 0.05 percent sulfur fuel.

Table A-36. DAILY EMISSIONS FROM DEVELOPMENT DRILLING - SANTA MARIA ZONE

Pollutant	Emissions (lb/day/well)[1]
HC	6
NO_x	73
SO_x	39
CO	17
TSP	5

1. Based on the emission factors for diesel fired turbines presented in Table A-1. Refer to Table A-32 for a summary of the drilling scenario.

Table A-37. DEVELOPMENT SUPPORT EMISSIONS - SANTA MARIA ZONE

Source	Emissions (lbs/day/platform)[1]				
	HC	NO_x	SO_x	CO	TSP
Supply Boat[2]	43	1,888	128	284	83
Crew Boat[3]	2	103	7	15	5
Helicopter[4]	6	7	2	68	3
Vehicular[5]	8	16	1	148	3
	59	2,014	138	515	94

1. Emissions/platform would be reduced 5 percent for each additional drilling platform to account for increased efficiency in transporting supplies and crews.

2. Based on the emission factors presented in Table A-1. Assumes 150 miles/round trip with 3 boats making 1 round trip/day. Based on an average speed of 13 knots and a fuel consumption rate of 110 gal/hr.

3. Based on the emission factors presented in Table A-1. Assumes 45 miles/round trip with 4 trips/day. Based on an average speed of 17 knots and a fuel consumption rate of 20 gal/hr.

4. Based on the emission factors presented in Table A-1. Assumes 2 engines/helicopter with 4 landing-takeoff (LTO) cycles daily onshore and 2 LTO cycles daily on the platform.

5. Based on the emission factors presented in Table A-1. Assumes 20 miles/vehicle/day with 200 personnel or 4000 vehicle-miles traveled/day.

Table A-38. PRODUCTION SUPPORT EMISSIONS - SANTA MARIA ZONE
(BASIS: 8 PLATFORMS)

Source	Emissions (lbs/day)				
	HC	NO_x	SO_x	CO	TSP
Supply Boat[1]	43	1,888	129	204	83
Crew Boat[2]	1	51	4	8	2
Helicopter[3]	4	4	2	46	2
Vehicular[4]	6	13	1	118	2
	54	1,956	136	376	89

1. Based on the emission factors presented in Table A-1. Assumes 1 supply boat/3 platforms and one 150 mile round trip/day/supply boat. Based on an average speed of 13 knots and a fuel consumption rate of 110 gal/hr.

2. Based on the emission factors presented in Table A-1. Assumes 1 crew boat/4 platforms and one 45 mile round trip/day/crewboat. Based on an average speed of 17 knots and a fuel consumption rate of 20 gal/hr.

3. Based on the emission factors presented in Table A-1. Assumes 1 helicopter/4 platforms with 2 landing-takeoff (LTO) cycles daily onshore and 1 LTO cycle daily on the platform. Helicopters were assumed to have 2 engines.

4. Based on the emission factors presented in Table A-1. Assumes 20 miles/vehicle/day with 20 personnel/platform or 3,200 vehicle-miles traveled/day.

Table A-39. DAILY EMISSIONS ASSOCIATED WITH OVERLAND PIPELINE INSTALLATION[1]

Emission Source	No.	Rated Output (hp)	Use Percent %	Load Factor %	Pollutants (lbs/day) THC	NO_x	SO_x	CO	TSP
Sidebooms CAT 342[2]	4	232	90	100	12.71	276.52	19.43	40.36	8.97
Backhoe CAT 235[2]	4	194	90	100	18.79	273.74	17.54	51.99	16.91
Welding Equipment[2]	4	45	30	100	1.62	20.02	1.36	4.34	1.42
Trucks (for Welding Equipment)[2,3]	4	180			0.40	1.84	0.24	2.52	0.12
Pickup Trucks[2,4]	4	180	25	100	0.18	0.20	—	2.38	—
Buldozer CAT 342[2]	2	173	75	100	5.29	115.22	8.10	16.82	3.74
Dump Truck[2,4]	2	225	75	100	0.60	2.77	0.37	3.80	0.17
Flatbed Truck[2,4]	2	180	50	100	0.60	2.77	0.37	3.80	0.17
Water Truck[2,3]	1	315	50	100	0.10	0.46	0.06	0.63	0.03
Field Joint Pot[2]	1	50	50	100	0.75	9.27	0.63	2.01	0.66
Truck (for Field Joint Pot)[2,3]	1	180			0.10	0.46	0.06	0.63	0.03
Vehicular[2,5]	50	—	—	—	2.00	4.00	neg.	37.00	0.70
TOTAL					43.14	707.27	48.16	166.28	32.92

1. Source: Woodward-Clyde Consultants, Environmental Impact Report for Chevron U.S.A Proposed Pipeline Installation, Santa Barbara Channel (1979).
2. Based on emission factors presented in Table A-1.
3. Assumes daily travel of 10 miles/truck.
4. Assumes daily travel of 20 miles/truck.

Table A-40. ANNUAL EMISSIONS ASSOCIATED WITH OVERLAND PIPELINE CONSTRUCTION

Zone	Miles Installed	Emissions (tons/year)[1] HC	NO_x	SO_x	CO	TSP
EEL RIVER						
Scenarios 1,1A,2,3	5	0.3	4	0.3	1	0.2
POINT ARENA						
Scenarios 1,2,3	33	2	29	2	7	2
Scenario 1A	35	2	31	2	7	2
SANTA CRUZ						
Scenarios 1,1A	94[2]	5	83	6	20	4
Scenarios 2,3	7	0.5	6	0.5	2	0.3
SANTA MARIA						
Scenarios 1,1A	68[2]	4	60	4	14	3
Scenarios 2,3	14	1	12	1	3	0.5

1. See Table A-39 for daily emissions from overland pipeline construction.

2. Includes both oil and gas delivery pipelines as shown in Table V-4.

Table A-41. EQUATIONS USED IN CALCULATING STORAGE TANK EMISSIONS FROM FLOATING ROOF TANKS

Standing Losses

$$L_s = 9.21 \times 10^{-3} M \left[\frac{P}{14.7-P}\right]^{0.7} D^{1.5} V_w^{0.7} K_t K_s K_p K_c$$

where: L_s = Floating roof standing storage loss (lbs/day)

M = Molecular weight of vapor in storage tank, 50 lbs/lb-mole

P = True vapor pressure at bulk liquid conditions, 2.8 psia @ 60°F

D = Tank diameter, 90 ft. for 50,000 bbl tank and 160 ft. for 170,000 bbl tank[1]

V_w = Average wind velocity, 4 mph

K_t = Tank type factor, 0.045 (dimensionless)

K_s = Seal factor, 0.25 (dimensionless)

K_p = Paint factor, 1.00 (dimensionless)

K_c = Crude oil factor, 0.84 (dimensionless)

Withdrawal Losses

$$L_{wd} = \frac{22.4\ d\ C_f}{D}$$

where: L_{wd} = Floating roof withdrawal loss (lbs/10^3 gal. throughput)

d = Density of stored liquid, 7.1 lbs/gal. at 60°F

C_f = Tank construction factor, 0.02 (dimensionless) for steel tanks

D = Tank diameter, 90 ft. for 50,000 bbl tank and 160 ft. for 170,000 bbl tank

Source: EPA AP-42 (1978)

1. For the case of D > 150, $D^{1.5}$ is used

TANKER/BARGE SCENARIOS SUPPORTING DATA

Table A-42. SHIPS CONSIDERED FOR TRANSPORTING OIL

Zone	Resource Recovery Estimate	Scenario 1 and 1A	Scenario 2	Scenario 3
Point Arena	95%	15,000 DWT tanker	15,000 DWT tanker	45,000 DWT tanker[2]
	5%	36,000 DWT tanker	36,000 DWT tanker	45,000 DWT tanker[4]
	Mean	25,000 DWT tanker	25,000 DWT tanker	45,000 DWT tanker[5]
Bodega	95%	5,000 bbl barge	5,000 bbl barge	25,000 DWT tanker[2]
	5%	40,000 bbl barge	40,000 bbl barge	25,000 DWT tanker
	Mean	15,000 bbl barge	15,000 bbl barge	25,000 DWT tanker[3]
Santa Cruz	95%	Not applicable[1]	5,000 bbl barge	43,000 DWT tanker
	5%		28,000 DWT tanker	45,000 DWT tanker[4]
	Mean		100,000 bbl barge	45,000 DWT tanker[2]
Santa Maria	95%	Not applicable[1]	11,000 DWT tanker	45,000 DWT tanker[3]
	5%		28,000 DWT tanker[2]	45,000 DWT tanker[6]
	Mean		28,000 DWT tanker	45,000 DWT tanker[7]

1. In these cases, oil would be transported to shore by pipeline.
2. A maximum of three tankers would be required to transport the quantity of oil recovered.
3. A maximum of two tankers would be required to transport the quantity of oil recovered.
4. A maximum of seven tankers would be required to transport the quantity of oil recovered.
5. A maximum of four tankers would be required to transport the quantity of oil recovered.
6. A maximum of nineteen tankers would be required to transport the quantity of oil recovered.
7. A maximum of ten tankers would be required to transport the quantity of oil recovered.

Table A-43. ESTIMATED TIMES FOR LOADING, UNLOADING AND TRANSIT TURNAROUND TIME (HOURS)

Zone	Resource Recovery Estimate	Turnaround Time (Hours)[1]		
		Scenario 1 or 1A	Scenario 2	Scenario 3
Point Arena	95%	53	53	696
	5%	68	68	696
	Mean	60.5	60.5	696
Bodega	95%	27.5	27.5	672
	5%	40.5	40.5	672
	Mean	33	33	672
Santa Cruz	95%	Not Applicable	26	672
	5%		49	672
	Mean		38	672
Santa Maria	95%	Not Applicable	57.5	648
	5%		62.5	648
	Mean		62.5	648

1. The values shown for Scenarios 1, 1A and 2 represent the total time that would be required for all ship activities as listed in Tables A-50 - A-64. The values shown for Scenario 3 represent data provided by the BLM (1979a).

Table A-44. FUEL CONSUMPTION RATES OF TANKERS AND BARGES PROPOSED FOR USE IN OCS LEASE SALE NO. 53 DEVELOPMENT

Vessel Type	Horsepower[1,2]	Fuel Consumption (gallons/hour) Operational Mode[3]			
		Full Power	Cruising	Hoteling	Pumping
5,000 bbl barge[4]	800 HP tugboat	30	30	30	35
15,000 bbl barge	800 HP tugboat	30	30	30	35
40,000 bbl barge	2,000 HP tugboat	75	75	75	80
100,000 bbl barge	2,000 HP tugboat	75	75	75	80
11,000 DWT tanker[5]	6,800 HP	434	195	48	121
15,000 DWT tanker	10,000 HP	638	287	70	143
25,000 DWT tanker	12,000 HP	765	344	84	157
28,000 DWT tanker	13,000 HP	829	373	91	164
36,000 DWT tanker	15,000 HP	956	430	105	178
45,000 DWT tanker	18,500 HP	1,179	531	130	203

1. Size of tugboat required to tow barge of stated size determined from data presented by Aerovironment, Inc. (1977).

2. Horsepower requirements calculated by interpolation of data presented by the California Air Resources Board, Ailor (1978).

3. Cruising would require 45 percent power, hoteling would require 11 percent power, tanker pumps would require an additional 73 gallons fuel per hour, and barge pumps would require an additional 5 gallons per hour.

4. Fuel consumption rates for tugboats from Goodley, et al (1977), rates for pumps from EPA AP-42 (1977).

5. Fuel consumption of 0.51 lbs/shaft horsepower hour from Woodward-Clyde Consultants (1979).

Table A-45. EMISSION FACTORS FOR TUGBOATS AND BARGES[1]

Activity	Units	HC	NO_x	SO_x	CO	TSP
Loading[2]	lbs/1,000 gal cargo	2.9	--	--	--	--
Sea Passage[3]	lbs/1,000 gal fuel	13	572	39	86	25
Unloading	lbs/1,000 gal fuel	37.5	469	28	102	35.5
(using barge pumps)[4]	lbs/hr	0.16	2.01	0.13	0.43	0.14
Breathing[4]	lb/hr/1,000 gal cargo	0.006				
Refueling[3]		1.5				

1. These factors are assumed applicable for an 800 horsepower tugboat towing either a 5,000 or 15,000 bbl barge and for a 2,000 horsepower tugboat towing either a 40,000 or 100,000 bbl barge.

2. Source: Aerovironment, Inc. (1977).

3. Source: Goodley, et al. (19676).

4. Source: EPA (1977).

Table A-46. EMISSION FACTORS FOR TANKERING OPERATIONS[1]

Activity	Units	Pollutants						
		HC	NO_x	SO_2[2]		CO	PM	
				2.0%S	0.5%S		2.0%S	0.5%S
Loading[3]	lbs/1000 gal loaded	0.97						
Sea Passage[4]	lbs/1000 gal fuel	3.10	50.24	319.08	79.77	0.60	19.05	7.14
Maneuvering[4]	lbs/1000 gal fuel	3.10	42.86	319.08	79.77	0.60	19.05	7.14
Hoteling[4]	lbs/1000 gal fuel	3.10	20.95	319.08	79.77	0.60	19.05	7.14
Offloading [4,5]	lbs/1000 gal fuel	3.10	50.24	319.08	79.77	0.60	19.05	7.14
Venting[6]	lbs/hr/1000 gal cargo	0.0060	--	--	--	--	--	--
Refueling[4]	lbs/visit	1.5	--	--	--	--	--	--
Ballasting[4,7]	lbs/DWT of ballast	0.20	--	--	--	--	--	--
Tugboat Assistance[4]	lbs/1000 gal diesel fuel	12.99	571.22	--	38.97	86	--	24.98
Purging[6,8]	lbs/1000 gal cargo	0.7	--	--	--	--	--	--
Operational Spills[4]	lbs/visit	1.0	--	--	--	--	--	--

1. These factors are assumed applicable for tankers ranging in size from 11,000 DWT to 45,000 DWT.

2. Fuel with a sulfur content of 0.5 percent by weight is assumed to be used when the vessel is docked (in either San Francisco or Los Angeles). Fuel with a sulfur content of 2.0 percent by weight is assumed to be used at all other times.

3. Source: Exxon Company, U.S.A. (1979).

4. Source: Goodley, et al. (1976).

5. Based on a pumping rate of 20,000 barrels/hour. Tankers with inerting systems would have offloading emissions reduced by 17 percent.

6. Source: U.S. EPA (1977).

7. Assumes vessel would ballast 0 to 20 percent while docked (Port of Long Beach, 1978).

8. This is considered a discretionary emission which is not expected during routine operations.

Table A-47. CRUDE OIL SHIP TRANSPORTATION NEEDS ASSOCIATED WITH OCS LEASE SALE NO. 53 DEVELOPMENT
(MEAN RESOURCE ESTIMATE)

Area	(Number of Shipments Required) 1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
							Transportation Scenarios 1 and 1A													
Point Arena[1,7]	19	55	84	95	81	68	58	48	41	35	29	25	20	18	15	13	10	10	7	6
Bodega[2,7]	48	116	100	88	80	68	60	56	48	44	36	32	28	24	24	20	16	16	12	12
Santa Cruz						Not Applicable														
Santa Maria						Not Applicable														
							Transportation Scenario 2													
Point Arena[1,7]	19	55	84	95	81	68	58	48	41	35	29	25	20	18	15	13	10	10	7	6
Bodega[2,7]	48	116	100	88	80	68	60	56	48	44	36	32	28	24	24	20	16	16	12	12
Santa Cruz[3]	6	35	73	106	123	115	101	89	79	69	61	54	48	42	37	33	29	25	22	20
Santa Maria[4,5]	15	67	127	178	199	211	190	164	142	121	106	91	78	68	58	51	43	38	31	28
							Transportation Scenario 3													
Point Arena[6,7]	10	29	45	50	42	36	30	26	22	18	15	13	11	9	8	7	6	5	4	4
Bodega[1]	7	17	14	13	12	10	9	8	7	6	5	5	4	4	4	3	3	3	2	2
Santa Cruz[6,7]	2	11	22	32	37	35	30	27	24	21	18	16	15	13	11	10	9	8	7	6
Santa Maria[6,7]	9	40	76	101	120	127	114	98	85	73	63	55	47	41	35	30	26	23	19	17

1. Based on the use of a 25,000 DWT tanker.
2. Based on the use of a 15,000 bbl barge.
3. Based on the use of a 100,000 bbl barge.
4. Based on the use of a 27,000 DWT tanker.
5. Two ships would be required in the years 1989 through 1993.
6. Based on the use of a 45,000 DWT tanker.
7. The OS&T would be partially full at the start of 2006.

Table A-48. CRUDE OIL SHIP TRANSPORTATION NEEDS ASSOCIATED WITH OCS LEASE SALE NO. 53 DEVELOPMENT
(LOW RESOURCE ESTIMATE)

Area	(Number of Shipments Required) 1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
							Transportation Scenarios 1 and 1A													
Point Arena[1]	34	96	105	104	88	74	62	53	45	38	32	27	23	19	16	14	12	10	8	7
Bodega[2]	80	140	140	120	120	120	100	100	80	80	80	60	60	60	60	60	40	40	40	40
Santa Cruz						Not Applicable														
Santa Maria						Not Applicable														
							Transportation Scenario 2													
Point Arena[1]	34	96	105	104	88	74	62	53	45	38	32	27	23	19	16	14	12	10	8	7
Bodega[2]	80	140	140	120	120	120	100	100	80	80	80	60	60	60	60	60	40	40	40	40
Santa Cruz[3]	40	140	180	260	260	240	220	200	200	180	160	160	140	140	120	120	100	100	80	80
Santa Maria[4]	13	45	63	85	106	101	91	82	75	68	61	56	51	45	42	37	35	30	28	26
							Transportation Scenario 3													
Point Arena[5]	10	29	32	31	27	22	19	16	14	12	10	8	7	6	5	4	4	3	3	2
Bodega[6]	3	4	4	4	4	4	3	3	3	3	3	2	2	2	2	2	2	2	2	2
Santa Cruz[5]	1	2	3	4	4	4	4	3	3	3	3	3	2	2	2	2	2	2	2	2
Santa Maria[5]	3	10	14	19	24	23	20	19	17	16	14	13	12	10	10	9	8	7	7	6

1. Based on the use of a 140,000 DWT tanker.
2. Based on the use of a 5,000 bbl barge.
3. Based on the use of a 5,000 bbl barge.
4. Based on the use of a 11,000 DWT tanker.
5. Based on the use of a 45,000 DWT tanker.
6. Based on the use of a 25,000 DWT tanker.

Table A-49. CRUDE OIL SHIP TRANSPORTATION NEEDS ASSOCIATED WITH OCS LEASE SALE NO. 53 DEVELOPMENT (HIGH RESOURCE ESTIMATE)

Area	(Number of Shipments Required) 1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
								Transportation Scenarios 1 and 1A												
Point Arena[1]	18	53	101	104	98	80	67	55	46	38	32	26	22	18	14	13	10	9	7	5
Bodega[2]	42	123	147	140	120	105	90	78	67	58	50	42	38	32	28	25	20	17	15	13
Santa Cruz						Not Applicable														
Santa Maria						Not Applicable														
								Transportation Scenario 2												
Point Arena[1]	18	53	101	104	98	80	67	55	46	38	32	26	22	18	14	13	10	9	7	5
Bodega[2]	42	123	147	140	120	105	90	78	67	58	50	42	38	32	28	25	20	17	15	13
Santa Cruz[3]	13	53	103	140	150	138	119	103	90	76	66	57	49	42	37	31	28	23	21	17
Santa Maria[4]	22	106	232	336	392	411	396	345	291	246	208	178	148	125	106	89	75	64	54	46
								Transportation Scenario 3												
Point Arena[5]	14	40	75	78	73	60	50	41	35	29	24	20	16	14	11	10	8	6	6	4
Bodega[6]	10	28	34	32	28	24	21	18	16	13	12	10	9	8	7	6	5	4	4	3
Santa Cruz[5]	8	32	62	84	90	83	71	62	51	46	39	34	30	26	22	19	17	14	12	11
Santa Maria[5]	13	64	139	202	235	247	238	207	175	148	125	105	89	76	64	54	45	38	32	27

1. Based on the use of a 36,000 DWT tanker.
2. Based on the use of a 40,000 bbl barge.
3. Based on the use of a 28,000 DWT tanker.
4. Based on the use of a 28,000 DWT tanker. One tanker would be sufficient for 1986, 1987, and 1999. Two tankers would be needed for 1988 and 1995 through 1998. Three tankers would be necessary for 1989 through 1994.
5. Based on the use of a 45,000 DWT tanker.
6. Based on the use of a 25,000 DWT tanker.

Table A-50. PER VISIT EMISSIONS ASSOCIATED WITH TRANSPORTATION SCENARIOS 1, 1A, AND 2 TANKERING OPERATIONS - POINT ARENA ZONE

(MEAN RESOURCE ESTIMATE)[1]

Location	Activity	Duration (Hours)	Fuel Consumption (gallons)	Pollutants (lbs/visit)[2] HC	NO_x	SO_x	CO	TSP
Offshore OS&T	Arrival & Tie-Up[3]	1	84	44	2	27	0.05	2
	Loading[4]							
	Pumping	13.75	1,520	5	54	485	0.9	29
	Fugitive		--	7,130	--	--	--	--
	Release & Departure[3]	1	84	44	2	27	0.05	2
	TOTAL			7,223	58	539	1	33
Offshore Transit[3,5]	Around OS&T	3	1,032	135	44	329	0.6	10
	Along Mendocino County	8.4	5,700	390	322	1,819	3	108
	Along Sonoma County	4.4	3,008	205	170	960	2	57
	Along Marin County	7.2	4,908	335	276	1,566	3	93
	Between Golden Gate Bridge and Dock	5	3,404	226	74	1,086	5	66
	Tugboats[6]	4.5	270	4	158	11	23	7
	TOTAL			1,294	1,044	5,771	36.6	341
Onshore Terminal	Arrival & Tie-Up[3]	2	168	89	4	14	0.3	4
	Unloading (Pumping)[7]	8.75	1,374	4	69	110	0.8	10
	Ballasting							
	Fuel Combustion	3	252	1	5	20	0.2	2
	Fugitive			1,000	--	--	--	--
	Release and Departure[3]	3	252	134	5	20	0.5	6
	Operational Spills			1	--	--	--	--
	TOTAL			1,229	83	164	1.8	22

Table A-50 (continued)

1. Tankers to be used in Transportation Scenarios 1, 1A, and 2 would be: 1) a 25,000 DWT ship for mean resource estimate; 2) a 15,000 DWT ship for low resource estimates; and 3) a 36,000 DWT ship for high resource estimate.

2. Emission factors used are given in Table A-46.

3. It was assumed that breathing losses would be included.

4. It was assumed that crude oil would be loaded at a rate of 20,000 bbl/hr. It was also assumed that pumping ballast from the ship requires five hours and that all ballast is removed before loading is begun (Aerovironment, Inc., 1977 and Exxon Company U.S.A., 1978).

5. It was assumed that distances and speeds used in apportioning the emissions for a round trip would be as follows:
   Manuevering about OS&T, 3 hours at 6 knots
   Along Mendocino County, 72 miles at 15 knots
   Along Sonoma County, 38 miles at 15 knots
   Along Marin County; 62 miles at 15 knots
   Landward of Golden Gate Bridge, 17 miles at 6 knots.

6. It was assumed that two tugboats would be required.

7. It was assumed that crude oil would be offloaded at a rate of 20,000 bbl/hr (Aerovironment, 1977).

Table A-51. PER VISIT EMISSIONS ASSOCIATED WITH TRANSPORTATION SCENARIOS 1,1A, AND 2 TANKERING OPERATIONS - POINT ARENA ZONE

(LOW RESOURCE ESTIMATE)[1]

Location	Activity	Duration (hours)	Fuel Consumption (gallons)	Pollutants (lbs/visit)[2] HC	NO_x	SO_x	CO	TSP
Offshore OS&T	Arrival & Tie-Up[3]	1	70	25	1	22	0.04	1
	Loading[4]							
	Pumping	10	490	3	43	340	0.64	21
	Fugitive			4,074	--	--	--	--
	Release & Departure[3]	1	70	26	2	23	0.04	1
	TOTAL			4,128	46	385	0.72	23
Offshore Transit[3,5]	Around OS&T	3	861	82	37	275	0.5	16
	Along Mendocino County	8.4	5,341	224	268	1,704	3	102
	Along Sonoma County	4.4	2,807	120	142	899	2	54
	Along Marin County	7.2	4,602	196	231	1,468	3	88
	Between Golden Gate Bridge and Dock	5	1,435	130	61	458	0.8	26
	Tugboats[6]	4.5	270	4	158	11	23	7
	TOTAL			756	897	4,815	32.3	293
Onshore Terminal	Arrival & Tie-Up[3]	2	140	51	36	57	0.43	5
	Unloading (Pumping)[7]	5	715	2	3	11	0.08	1
	Ballasting							
	Fuel Combustion	5	210	0.7	4	17	0.04	2
	Fugitive			600	--	--	--	--
	Release and Departure[3]	3	210	76	5	17	0.13	2
	Operational Spills			1	--	--	--	--
	TOTAL			730.7	48	102	0.68	9

Table A-51 (continued)

1. Tankers to be used in Transportation Scenarios 1, 1A, and 2 would be: 1) a 25,000 DWT ship for mean resource estimate; 2) a 15,000 DWT ship for low resource estimates; and 3) a 36,000 DWT ship for high resource estimate.

2. Emission factors used are given in Table A-46.

3. It was assumed that breathing losses would be included.

4. It was assumed that crude oil would be loaded at a rate of 20,000 bbl/hr. It was also assumed that pumping ballast from the ship requires five hours and that all ballast is removed before loading is begun (Aerovironment, Inc., 1977 and Exxon Company U.S.A., 1978).

5. It was assumed that distances and speeds used in apportioning the emissions for a round trip would be as follows:
   Maneuvering about OS&T, 3 hours at 6 knots
   Along Mendocino County, 72 miles at 15 knots
   Along Sonoma County, 38 miles at 15 knots
   Along Marin County, 62 miles at 15 knots
   Landward of Golden Gate Bridge, 17 miles at 6 knots.

6. It was assumed that two tugboats would be required.

7. It was assumed that crude oil would be offloaded at a rate of 20,000 bbl/hr (Aerovironment, 1977).

Table A-52. PER VISIT EMISSIONS ASSOCIATED WITH TRANSPORTATION SCENARIOS 1, 1A, AND 2 TANKERING OPERATIONS - POINT ARENA ZONE

(HIGH RESOURCE ESTIMATE)[1]

Location	Activity	Duration (Hours)	Fuel Consumption (gallons)	Pollutants (lbs/visit)[2] HC	NO_x	SO_x	CO	TSP
Offshore OS&T	Arrival & Tie-Up[3]	1	105	63	2	33	0.06	2
	Loading[4]							
	Pumping	17.5	2,180	7	73	703	1	42
	Fugitive			10,185	--	--	--	--
	Release & Departure[3]	1	105	64	2	34	0.06	2
	TOTAL			10,319	77	770	1.12	46
Offshore Transit[3,5]	Around OS&T	3	1,290	194	55	412	0.8	25
	Along Mendocino County	8.4	8,005	551	403	2,554	5	152
	Along Sonoma County	4.4	4,225	291	212	1,348	2	80
	Along Marin County	7.2	6,890	476	346	2,199	4	132
	Between Golden Gate Bridge and Dock	5	2,150	322	92	686	6	41
	Tugboats[6]	4.5	270	4	158	11	23	7
	TOTAL			1,838	1,266	7,210	46.8	437
Onshore Terminal	Arrival & Tie-Up[3]	2	210	127	4	17	0.13	2
	Unloading (Pumping)[7]	12.5	2,225	317	112	178	1.3	16
	Ballasting							
	Fuel Combustion	3	1,755	5	7	25	0.19	2
	Fugitive			1,436	--	--	--	--
	Release and Departure[3]	3	315	190	7	25	0.19	2
	Operational Spills			1	--	--	--	--
	TOTAL			1,766	130	245	1.81	22

Table A-52 (continued)

1. Tankers to be used in Transportation Scenarios 1, 1A, and 2 would be: 1) a 25,000 DWT ship for mean resource estimate; 2) a 15,000 DWT ship for low resource estimates; and 3) a 36,000 DWT ship for high resource estimate.

2. Emission factors used are given in Table A-46.

3. It was assumed that breathing losses would be included

4. It was assumed that crude oil would be loaded at a rate of 20,000 bbl/hr. It was also assumed that pumping ballast from the ship requires five hours and that all ballast is removed before loading is begun (Aerovironment, Inc., 1977 and Exxon Company U.S.A., 1978).

5. It was assumed that distances and speeds used in apportioning the emissions for a round trip would be as follows:
   Manuevering about OS&T, 3 hours at 6 knots
   Along Mendocino County, 72 miles at 15 knots
   Along Sonoma County, 38 miles at 15 knots
   Along Marin County, 62 miles at 15 knots
   Landward of Golden Gate Bridge, 17 miles at 6 knots.

6. It was assumed that two tugboats would be required.

7. It was assumed that crude oil would be offloaded at a rate of 20,000 bbl/hr (Aerovironment, 1977).

Table A-53. PER VISIT EMISSIONS ASSOCIATED WITH TRANSPORTATION SCENARIO 3 TANKERING OPERATIONS - POINT ARENA ZONE[1] (LOW, MEAN, AND HIGH RESOURCE ESTIMATES)

Location	Activity	Time (hours)	Fuel Consumption (gallons)	Pollutants (lbs/visit)[2] HC	NO_x	SO_x	CO	TSP
Offshore OS&T	Ballast Discharge	5	1,015	3.2	51.0	323.9	0.6	19.3
	Hoteling	2	260	0.8	5.5	83.0	0.2	5.0
	Loading[3]							
	Pumping	17	3,451	10.7	173.4	1,101.2	2.1	65.7
	Fugitive			13,587	--	--	--	--
	TOTAL			13,601.7	229.9	1,508.1	2.9	90.0
Offshore Transit	Near OS&T	3	1,593	4.9	68.3	508.3	1.0	30.4
	Along Mendocino County[4]	3.8	2,240	13.9	225.1	1,429.5	2.7	85.3
	TOTAL			18.8	293.4	1,937.8	3.7	115.7

1. Based on the use of a 45,000 deadweight ton (DWT) tanker.

2. Based on the emission factors presented in Table A-46.

3. Based on a crude oil loading rate of 20,000 bbls/hr.

4. Based on a round trip distance of 60 nautical miles in waters adjacent to the Mendocino County and a speed of 16 knots.

Table A-54. PER VISIT EMISSIONS ASSOCIATED WITH TRANSPORTATION SCENARIOS 1, 1A, AND 2 TANKERING OPERATIONS - BODEGA ZONE (MEAN RESOURCE ESTIMATE)[1]

Location	Activity	Duration (hours)	Fuel Consumption (gallons)	Pollutants (lbs/visit)[2] HC	NO_x	SO_x	CO	TSP
Offshore OS&T	Arrival & Tie-Up[3]	1	30	4	17	1	3	0.8
	Loading[4]							
	Pumping	3	90	1	51	4	8	2
	Fugitive			1,827	--	--	--	--
	Release & Departure[3]	1	30	4	17	1	3	0.8
	TOTAL			1,836	85	6	14	3.6
Offshore Transit[3,5]	Around OS&T	3	90	13	51	4	8	2
	To the Golden Gate Bridge	7.5	225	41	169	9	19	6
	Between Golden Gate Bridge and Dock	5	150	11	45	6	13	4
	TOTAL			65	265	18	40	12
Onshore Terminal	Arrival & Tie-Up[3]	2	60	8	34	2	5	2
	Unloading (Pumping)[6]	7.5	261	4	144	10	23	7
	Release & Departure[3]	3	90	13	51	4	8	2
	Operational Spills			1	--	--	--	--
	TOTAL			26	229	16	36	11

Table A-54 (continued)

1. Transportation Scenarios 1, 1A and 2 would use the following vessels: for the mean resource estimate - an 800 horsepower tugboat towing a 15,000 bbl barge; for the low resource estimate - an 800 horsepower tugboat towing a 5,000 bbl barge; and for the high resource estimate - a 2,000 horsepower tugboat towing a 40,000 bbl barge.

2. Emission factors are presented in Table A-45.

3. It was assumed that breathing losses would be included.

4. It was assumed that loading rates used would be 5,000 bbl/hr for 15,000 and 40,000 bbl barges and 2,000 bbl/hr for 5,000 bbl barge. Source: Aerovironment, Inc. (1977).

5. It was assumed that distances and speeds for apportioning these emissions would be as follows:

   Around platform - 3 hours maneuvering.
   Sea passage to the Golden Gate Bridge - 56 nautical miles, traveled at 15 knots.
   Between bridge and dock - 15 nautical miles, traveled at 6 knots.

6. It was assumed that offloading crude oil, using barge pumps, would be done at a rate of 2,000 bbl/hr. Source: Aerovironment, Inc. (1977).

Table A-55. PER VISIT EMISSIONS ASSOCIATED WITH TRANSPORTATION SCENARIOS 1,1A and 2 TANKERING OPERATIONS - BODEGA ZONE (LOW RESOURCE ESTIMATE)[1]

Location	Activity	Duration (hours)	Fuel Consumption (gallons)	Pollutants (lbs/visit)[2] HC	NO_x	SO_x	CO	TSP
Offshore OS&T	Arrival & Tie-Up[3]	1	30	2	17	1	3	0.8
	Loading[4]							
	Pumping	2.5	75	1	43	3	6	2
	Fugitive			609	--	--	--	--
	Release & Departure[3]	1	30	2	17	1	3	0.8
	TOTAL			613	77	5	12	3.6
Offshore Transit[3,5]	Around OS&T	3	90	13	51	4	8	2
	To the Golden Gate Bridge	7.5	225	41	169	9	19	6
	Between Golden Gate and Dock	5	150	11	45	6	13	4
	TOTAL			65	265	19	40	12
Onshore Terminal	Arrival & Tie-Up[3]	2	60	8	34	2	5	2
	Unloading (Pumping)[6]	2.5	87	1	48	3	8	2
	Release & Departure[3]	3	90	13	51	4	8	2
	Operational Spills			1	--	--	--	--
	TOTAL			23	133	9	21	6

Table A-55 (continued)

1. Transportation Scenarios 1, 1A and 2 would use the following vessels: for the mean resource estimate - an 800 horse power tugboat towing a 15,000 bbl barge; for the low resource estimate - an 800 horsepower tugboat towing a 5,000 bbl barge; and for the high resource estimate - a 2,000 horsepower tugboat towing a 40,000 bbl barge.

2. Emission factors are presented in Table A-45.

3. It was assumed that breathing losses would be included.

4. It was assumed that loading rates used would be 5,000 bbl/hr for 15,000 and 40,000 bbl barges and 2,000 bbl/hr for 5 bbl barge. Source: Aerovironment, Inc. (1977).

5. It was assumed that distances and speeds for apportioning these emissions would be as follows:

   Around platform - 3 hours maneuvering.
   Sea Passage to the Golden Gate Bridge - 56 nautical miles, traveled at 15 knots.
   Between bridge and dock - 15 nautical miles, traveled at 6 knots.

6. It was assumed that offloading crude oil, using barge pumps, would be done at a rate of 2,000 bbl/hr. Source: Aerovironment, Inc. (1977).

Table A-56. PER VISIT EMISSIONS ASSOCIATED WITH TRANSPORTATION SCENARIOS 1,1A and 2 TANKERING OPERATIONS - BODEGA ZONE (HIGH RESOURCE ESTIMATE)[1]

Location	Activity	Duration (hours)	Fuel Consumption (gallons)	Pollutants (lbs/visit)[2] HC	NO_x	SO_x	CO	TSP
Offshore OS&T	Arrival & Tie-Up[3]	1	75	11	43	3	6	2
	Loading[4]							
	Pumping	8	600	8	343	23	52	15
	Fugitive			4,872	--	--	--	--
	Release & Departure[3]	1	75	11	43	3	6	2
	TOTAL			4,902	429	29	64	19
Offshore Transit[3,5]	Around OS&T	3	225	33	129	9	19	18
	To the Golden Gate Bridge	7.5	563	83	322	26	64	6
	Between Golden Gate and Dock	5	375	55	214	8	17	5
	TOTAL			171	665	43	100	29
Onshore Terminal	Arrival & Tie-Up[3]	2	150	23	86	6	13	4
	Unloading (Pumping)[6]	20	1,595	23	898	61	138	40
	Release & Departure[3]	3	225	34	128	9	19	6
	Operational Spills			1	--	--	--	--
	TOTAL			81	1,112	76	170	50

Table A-56 (continued)

1. Transportation Scenarios 1, 1A and 2 would use the following vessels: for the mean resource estimate - an 800 horse power tugboat towing a 15,000 bbl barge; for the low resource estimate - an 800 horsepower tugboat towing a 5,000 bbl barge; and for the high resource estimate - a 2,000 horsepower tugboat towing a 40,000 bbl barge.

2. Emission factors are presented in Table A-45.

3. It was assumed that breathing losses would be included.

4. It was assumed that loading rates used would be 5,000 bbl/hr for 15,000 and 40,000 bbl barges and 2,000 bbl/hr for 5 bbl barge. Source: Aerovironment, Inc. (1977).

5. It was assumed that distances and speeds for apportioning these emissions would be as follows:

   Around platform - 3 hours maneuvering.
   Sea Passage to the Golden Gate Bridge - 56 nautical miles, traveled at 15 knots.
   Between bridge and dock - 15 nautical miles, traveled at 6 knots.

6. It was assumed that offloading crude oil, using barge pumps, would be done at a rate of 2,000 bbl/hr. Source: Aerovironment, Inc. (1977).

Table A-57. PER VISIT EMISSIONS ASSOCIATED WITH TRANSPORTATION SCENARIO 3 TANKERING OPERATIONS - BODEGA ZONE[1] (LOW, MEAN, AND HIGH RESOURCE ESTIMATES)

Location	Activity	Time (hours)	Fuel Consumption (gallons)	Pollutants (lbs/visit)[2] HC	NO_x	SO_x	CO	TSP
Offshore OS&T	Ballast Discharge	5	785	2.4	39.4	250.5	0.5	15.0
	Hoteling	2	168	0.5	3.5	53.6	0.1	3.2
	Loading[3]							
	Pumping	9	1,413	4.4	71.0	450.9	0.9	26.9
	Fugitive			7,130	--	--	--	--
	TOTAL			7,137.3	113.9	755.0	1.5	45.1
Offshore Transit	Near OS&T	3	1,032	3.2	44.2	329.3	0.6	19.7
	Along BAAQMD[4]	9.2	7,038	21.8	353.6	2,245.7	4.2	134.1
	TOTAL			25.0	397.8	2,575.0	4.8	153.8

1. Based on the use of a 25,000 deadweight ton (DWT) tanker.

2. Based on the emission factors presented in Table A-46.

3. Based on a crude oil loading rate of 20,000 bbls/hr.

4. Based on a round trip distance of 146 nautical miles in waters adjacent to the Bay Area Air Quality Management District and a speed of 16 knots.

Table A-58. PER VISIT EMISSIONS ASSOCIATED WITH TRANSPORTATION SCENARIO 2 TANKERING OPERATIONS - SANTA CRUZ ZONE (MEAN RESOURCE ESTIMATE)[1]

Location	Activity	Duration (hours)	Fuel Consumption (gallons)	Pollutants (lbs/visit)[2] HC	NO_x	SO_x	CO	TSP
Offshore OS&T	Loading[4]							
	Pumping	7	525	7	300	20	45	13
	Fugitive			12,180	--	--	--	--
	Release & Departure[3]	1	75	26	43	3	6	2
	TOTAL			12,239	386	26	58	17
Offshore Transit[3,5]	Around OS&T	3	225	78	129	9	19	6
	Along Santa Cruz County	1	75	26	43	3	6	2
	Along San Mateo County	3	225	78	129	9	19	6
	Along San Francisco to Golden Gate Bridge	2	150	53	86	6	13	4
	Between Golden Gate Bridge and Dock	5	375	131	215	15	32	9
	TOTAL			366	601	41	90	26
Onshore Terminal	Arrival & Tie-Up[3]	2	150	53	86	6	13	8
	Unloading (Pumping)[6]	10	798	11	449	31	69	20
	Release & Departure[3]	3	225	79	128	9	19	12
	Operational Spills			1	--	--	--	--
	TOTAL			144	663	46	101	40

Table A-58 (continued)

1. The vessels expected to be used in Transportation Scenario 2 would be: for the mean resource estimate - a 2,000 horsepower tugboat towing a 100,000 bbl barge; for the low resource estimate - an 800 horsepower tugboat towing a 5,000 bbl barge; and the high resource estimate - a 28,000 DWT tanker.

2. Emission factors are presented in Tables A-45 and A-46.

3. It was assumed that breathing losses would be included.

4. It was assumed that crude oil loading rates would be 2,000 bbl/hr for 5,000 bbl barge, 15,000 bbl/hr for a 100,000 bbl barge and 20,000 bbl/hr for a 28,000 DWT tanker. Source: Aerovironment, Inc. (1977).

5. It was assumed that distances and speeds used in apportioning these emissions would be as follows:

Adjacent Coastal County	Nautical Miles of Coastline (round trip)	Ship Speed (knots)
Santa Cruz (near OS&T)	3 hours	6
Santa Cruz	10 hours	15
San Mateo	42 hours	15
San Francisco (to Golden Gate Bridge)	30 hours	15
Between Golden Gate Bridge and Dock	30 hours	6

6. It was assumed that ship pumps would offload crude oil at 2,000 bbl/hr for 5,000 bbl barge, 10,000 bbl/hr for 100,000 bbl barge and 20,000 bbl/hr for a 28,000 DWT ship. Source: Aerovironment, Inc. (1977).

Table A-59. PER VISIT EMISSIONS ASSOCIATED WITH TRANSPORTATION SCENARIO 2 TANKERING OPERATIONS - SANTA CRUZ ZONE (LOW RESOURCE ESTIMATE)[1]

Location	Activity	Duration (hours)	Fuel Consumption (gallons)	Pollutants (lbs/visit)[2] HC	NO_x	SO_x	CO	TSP
Offshore OS&T	Arrival & Tie-Up[3]	1	30	2	17	1	2	0.8
	Loading[4]							
	Pumping	2.5	75	1	43	3	6	2
	Fugitive			609	--	--	--	--
	Release & Departure[3]	1	30	2	17	1	2	0.8
	TOTAL			614	77	5	10	3
Offshore Transit[3,5]	Around OS&T	3	90	5	51	3	8	2
	Along Santa Cruz County	1	30	2	17	1	2	0.8
	Along San Mateo County	3	90	5	51	3	8	2
	Along San Francisco to Golden Gate Bridge	2	60	3	35	2	5	1
	Between Golden Gate Bridge and Dock	5	150	8	86	6	13	4
	TOTAL			23	241	15	36	10
Onshore Terminal	Arrival & Tie-Up[3]	2	60	4	34	2	5	2
	Unloading (Pumping)[6]	2.5	87	1	48	3	8	2
	Release & Departure[3]	3	90	10	52	4	8	2
	Operational Spills			1	--	--	--	--
	TOTAL			16	134	9	21	6

Table A-59 (continued)

1. The vessels expected to be used in Transportation Scenario 2 would be: for the mean resource estimate - a 2,000 horsepower tugboat towing a 100,000 bbl barge; for the low resource estimate - an 800 horsepower tugboat towing a 5,000 bbl barge; and the high resource estimate - a 28,000 DWT tanker.

2. Emission factors are presented in Tables A-45 and A-46.

3. It was assumed that breathing losses would be included.

4. It was assumed that crude oil loading rates would be 2,000 bbl/hr for 5,000 bbl barge; 15,000 bbl/hr for a 100,000 bbl barge and 20,000 bbl/hr for a 28,000 DWT tanker. Source: Aerovironment, Inc. (1977).

5. It was assumed that distances and speeds used in apportioning these emissions would be as follows:

Adjacent Coastal County	Nautical Miles of Coastline (round trip)	Ship Speed (knots)
Santa Cruz (near OS&T)	3 hours	6
Santa Cruz	10 hours	15
San Mateo	42 hours	15
San Francisco (to Golden Gate Bridge)	30 hours	15
Between Golden Gate Bridge and Dock	30 hours	6

6. It was assumed that ship pumps would offload crude oil at 2,000 bbl/hr for 5,000 bbl barge, 10,000 bbl/hr for 100,000 bbl barge and 20,000 bbl/hr for a 28,000 DWT ship. Source: Aerovironment, Inc. (1977).

Table A-60. PER VISIT EMISSIONS ASSOCIATED WITH TRANSPORTATION SCENARIO 2 TANKERING OPERATIONS - SANTA CRUZ ZONE (HIGH RESOURCE ESTIMATE)[1]

Location	Activity	Duration (hours)	Fuel Consumption (gallons)	Pollutants (lbs/visit)[2] HC	NO_x	SO_x	CO	TSP
Offshore OS&T	Arrival & Tie-Up[3]	1	91	50	2	29	0.06	2
	Loading[5,7]							
	Pumping	15	1,730	5	60	552	1	33
	Fugitive			7,987	--	--	--	--
	Release & Departure[3]	1	91	51	2	29	0.06	2
	TOTAL			8,093	64	610	1.12	37
Offshore Transit[3,5]	Around OS&T		1,119	154	48	357	0.7	11
	Along Santa Cruz County	1	829	52	32	265	0.5	16
	Along San Mateo County	3	2,487	156	125	794	2	46
	Along San Francisco to Golden Gate Bridge	2	1,658	104	83	529	1	32
	Between Golden Gate Bridge and Dock	5	1,865	253	80	595	1	36
	Tugboat Assistance[8]	4.5	270	4	158	11	23	7
	TOTAL			723	536	2,550	28.2	158
Onshore Terminal	Arrival & Tie-Up[3]	2	182	99	4	14	0.1	1
	Unloading (Pumping)[6]	10	1,640	5	82	131	1	12
	Ballasting							
	Fuel Consumption[9]	3	273	1	6	22	0.2	2
	Fugitive			1,120	--	--	--	--
	Release & Departure	3	273	149	6	22	0.2	2
	Operational Spills			1	--	--	--	--
	TOTAL			1,375	98	189	1.5	17

Table A-60 (continued)

1. The vessels expected to be used in Transportation Scenario 2 would be: for the mean resource estimate - a 2,000 horsepower tugboat towing a 100,000 bbl barge; for the low resource estimate - an 800 horsepower tugboat towing a 5,000 bbl barge; and the high resource estimate - a 28,000 DWT tanker.

2. Emission factors are presented in Tables A-45 and A-46.

3. It was assumed that breathing losses would be included.

4. It was assumed that crude oil loading rates would be 2,000 bbl/hr for 5,000 bbl barge, 15,000 bbl/hr for a 100,000 bbl barge and 20,000 bbl/hr for a 28,000 DWT tanker. Source: Aerovironment, Inc. (1977).

5. It was assumed that distances and speeds used in apportioning these emissions would be as follows:

Adjacent Coastal County	Nautical Miles of Coastline (round trip)	Ship Speed (knots)
Santa Cruz (near OS&T)	3 hours	6
Santa Cruz	10 hours	15
San Mateo	42 hours	15
San Francisco (to Golden Gate Bridge)	30 hours	15
Between Golden Gate Bridge and Dock	30 hours	6

6. It was assumed that ship pumps would offload crude oil at 2,000 bbl/hr for 5,000 bbl barge, 10,000 bbl/hr for 100,000 bbl barge and 20,000 bbl/hr for a 28,000 DWT ship. Source: Aerovironment, Inc. (1977).

7. It was assumed that five additional hours would be required to pump ballast from tankers. Source: Exxon Company, U.S.A., 1978.

8. It was assumed that two tugboats would be required.

9. It was assumed that no auxiliary power would be needed.

Table A-61. PER VISIT EMISSIONS ASSOCIATED WITH TRANSPORTATION SCENARIO 3 TANKERING OPERATIONS - SANTA CRUZ ZONE[1] (LOW, MEAN, AND HIGH RESOURCE ESTIMATES)

Location	Activity	Time (hours)	Fuel Consumption (gallons)	Pollutants (lbs/visit)[2] HC	NO_x	SO_x	CO	TSP
Offshore OS&T	Ballast Discharge	5	1,015	3.2	51.0	323.9	0.6	19.3
	Moteling	2	260	0.8	5.5	83.0	0.2	5.0
	Loading[3]							
	Pumping	17	3,451	10.7	173.4	1,101.2	2.1	65.7
	Fugitive			13,587	--	--	--	--
	TOTAL			13,601.7	229.9	1,508.1	2.9	90.0
Offshore Transit	Near OS&T	3	1,593	4.9	68.3	508.3	1.0	30.4
	Along BAAQMD[4]	2.6	3,066	9.5	154.0	978.3	1.8	58.4
	Along Santa Cruz County[4]	2.8	3,302	10.2	165.9	1,053.6	2.0	62.9
	TOTAL			24.6	388.2	2,540.0	4.8	151.7

1. Based on the use of a 45,000 deadweight ton (DWT) tanker.

2. Based on the emission factors presented in Table A-46.

3. Based on a crude oil loading rate of 20,000 bbls/hr.

4. Based on a round trip distance of 40 nautical miles in waters adjacent to the Bay Area Air Quality Management District and 46 nautical miles in waters adjacent to Santa Cruz County. The speed of the tanker was assumed to be 16 knots.

Table A-62. PER VISIT EMISSIONS ASSOCIATED WITH TRANSPORTATION SCENARIO 2 TANKERING OPERATIONS - SANTA MARIA ZONE (MEAN AND HIGH RESOURCE ESTIMATES)[1]

Location	Activity	Duration (hours)	Fuel Consumption (gallons)	Pollutants (lbs/visit)[2] HC	NO_x	SO_x	CO	TSP
Offshore OS&T	Arrival & Tie-Up[3]	1	91	50	2	29	0.05	2
	Loading[4]							
	Pumping	15	1,730	5	60	552	1	33
	Fugitive			7,985	--	--	--	--
	Release & Departure[3]	1	91	51	2	29	0.06	2
	TOTAL			8,092	64	610	1.11	37
Offshore Transit[3,5]	Around OS&T	3	1,119	152	48	357	0.7	21
	Along San Luis Obispo County	1.6	1,338	88	67	427	0.8	25
	Along Santa Barbara County	12.6	20,427	666	524	3,327	6	200
	Along Ventura County	3.6	3,018	192	151	963	2	57
	Along Los Angeles County	5.2	5,049	378	249	1,611	3	96
	Tugboats[6]	6	360	5	206	14	31	9
	TOTAL			1,481	1,245	6,699	43.5	408
Onshore Terminal	Arrival & Tie-Up[3]	2	182	102	4	19	0.11	1
	Unloading (Pumping)	10	1,640	5	82	131	1	12
	Ballasting							
	Fuel Combustion	3	273	1	6	22	0.16	2
	Fugitive			1,120	--	--	--	--
	Release & Departure[3]	3	228	128	5	24	0.14	2
	Operational Spills			1	--	--	--	--
	TOTAL			1,357	98	196	1.41	17

Table A-62 (continued)

1. Tankers to be used in Transportation Scenario 2 would be: 1) for mean and high resource estimates, 28,000 DWT ships, and 2) for low resource estimates, 11,000 DWT ships.

2. Emission factors are presented in Table A-46.

3. It was assumed that breathing losses would be included.

4. It was assumed that crude oil loading rate would be 20,000 bbl/hr. It was also assumed that an additional five hours would be needed to pump off ballast before loading is begun. Sources: Aerovironment, Inc. (1977) and Exxon Company, U.S.A. (1978).

5. It was assumed that round trip distances and speeds needed to apportion transit emissions would be as follows:

   Maneuvering about OS&T in San Luis Obispo County for three hours.
   Along San Luis Obispo County - 27 miles at 15 knots.
   Along Santa Barbara County - 211 miles at 15 knots.
   Along Ventura County - 61 miles at 15 knots.
   Along Los Angeles County - 87 miles at 15 knots.
   Near Port of Los Angeles - 14 miles at 6 knots.

6. It was assumed that two tugboats would be needed.

Table A-63. PER VISIT EMISSIONS ASSOCIATED WITH TRANSPORTATION 2 TANKERING OPERATIONS - SANTA MARIA ZONE (LOW RESOURCE ESTIMATE)[1]

Location	Activity	Duration (hours)	Fuel Consumption (gallons)	Pollutants (lbs/visit)[2] HC	NO_x	SO_x	CO	TSP
Offshore OS&T	Arrival & Tie-Up[3]	1	48	29	1	15	0.03	1
	Loading[4]							
	Pumping	10	1,190	3	42	270	0.5	17
	Fugitive			3,055	--	--	--	--
	Release & Departure[3]	1	48	30	1	16	0.03	0.9
	TOTAL			3,096	44	301	0.56	18.9
Offshore Transit[3,5]	Around OS&T	3	585	58	25	187	0.35	11
	Along San Luis Obispo County	1.6	700	34	35	223	0.48	13
	Along Santa Barbara County	12.6	5,456	254	274	1,741	3	104
	Along Ventura County	3.6	1,576	74	79	503	1	30
	Along Los Angeles County	5.2	2,639	144	130	842	2	51
	Tugboats[6]	6	360	5	206	14	31	90
	TOTAL			569	749	3,510	37.83	218
Onshore Terminal	Arrival & Tie-Up[3]	2	96	38	2	8	0.06	0.2
	Unloading (Pumping)	5	605	2	30	48	0.4	4
	Ballasting							
	Fuel Combustion	3	144	0.4	3	11	0.09	0.1
	Fugitive			429	--	--	--	--
	Release & Departure[3]	2.5	120	48	2	9	0.07	2
	Operational Spills			1	--	--	--	--
	TOTAL			518.4	37	76	0.6	6.3

Table A-63 (continued)

1. Tankers to be used in Transportation Scenario 2 would be 1) for mean and high resource estimates, 28,000 DWT ships and 2) for low resource estimate, 11,000 DWT ships.

2. Emission factors are presented in Table A-46.

3. It was assumed that breathing losses would be included.

4. It was assumed that crude oil loading rate would be 20,000 bbl/hr. It was also assumed that an additional five hours would be needed to pump off ballast before loading is begun. Sources: Aerovironment, Inc. (1977) and Exxon Company, U.S.A. (1978).

5. It was assumed that round trip distances and speeds needed to apportion transit emissions would be as follows:

   Maneuvering about OS&T in San Luis Obispo County for three hours.
   Along San Luis Obispo County - 27 miles at 15 knots.
   Along Santa Barbara County - 211 miles at 15 knots.
   Along Ventura County - 61 miles at 15 knots.
   Along Los Angeles County - 87 miles at 15 knots.
   Near Port of Los Angeles - 14 miles at 6 knots.

6. It was assumed that two tugboats would be needed.

Table A-64. PER VISIT EMISSIONS ASSOCIATED WITH TRANSPORTATION SCENARIO 3 TANKERING OPERATIONS - SANTA MARIA ZONE[1] (LOW, MEAN, AND HIGH RESOURCE ESTIMATES)

Location	Activity	Time (hours)	Fuel Consumption (gallons)	Pollutants (lbs/visit)[2] HC	NO_x	SO_x	CO	TSP
Offshore OS&T	Ballast Discharge	5	1,015	3.2	51.0	323.9	0.6	19.3
	Hoteling	2	260	0.8	5.5	83.0	0.2	5.0
	Loading[3]							
	Pumping	17	3,451	10.7	173.4	1,101.2	2.1	65.7
	Fugitive			13,587	--	--	--	--
	TOTAL			13,601.7	229.9	1,508.1	2.9	90.0
Offshore Transit	Near OS&T	3	1,593	4.9	68.3	508.3	1.0	30.4
	Along Mendocino County[4]	3.8	2,240	13.9	225.1	1,429.5	2.7	85.3
	TOTAL			18.8	293.4	1,937.8	3.7	115.7

1. Based on the use of a 45,000 deadweight ton (DWT) tanker.

2. Based on the emission factors presented in Table A-46.

3. Based on a crude oil loading rate of 20,000 bbls/hr.

4. Based on a round trip distance of 60 nautical miles in waters adjacent to the Mendocino County and a speed of 16 knots.

AIR EMISSIONS ASSOCIATED WITH USGS HIGH AND LOW RESOURCE ESTIMATES

Table A-65. MAXIMUM ANNUAL HYDROCARBON EMISSIONS ASSOCIATED WITH LEASE SALE NO. 53 OCS OIL AND GAS DEVELOPMENT - TONS PER YEAR

(LOW RESOURCE ESTIMATE - HIGH RESOURCE ESTIMATE)[1]

Proposed Zone	Transportation Scenario 1	Transportation Scenario 1-A	Transportation Scenario 2	Transportation Scenario 3
Eel River[1]	1,164 - 2,899	1,164 - 2,899	1,164 - 2,899	1,164 - 2,899
Point Arena[2]	1,680 - 4,298	1,680 - 4,298	1,680 - 4,298	1,618 - 4,141
Bodega[3]	70 - 567	70 - 567	70 - 567	35 - 309
Santa Cruz[4]	183 - 4,179	184 - 4,183	262 - 4,633	204 - 4,674
Santa Maria[5]	1,131 -11,470	1,135 -11,518	1,310 -13,206	1,263 -12,834

1. Refer to Section V.D.3 for greater detail on the relative magnitude and location of the various emission sources contributing to the total emissions presented for each transportation scenario.

Table A-66. MAXIMUM ANNUAL NITROGEN OXIDE EMISSIONS ASSOCIATED WITH LEASE SALE NO. 53 OCS OIL AND GAS DEVELOPMENT - TONS PER YEAR

(LOW RESOURCE ESTIMATE - HIGH RESOURCE ESTIMATE)[1]

Proposed Zone	Transportation Scenario 1	Transportation Scenario 1-A	Transportation Scenario 2	Transportation Scenario 3
Eel River	238 - 1,208	238 - 1,208	238 - 1,208	238 - 1,208
Point Arena	1,035 - 2,035	1,081 - 2,035	1,035 - 2,035	1,035 - 2,001
Bodega	730 - 1,137	730 - 1,137	730 - 1,137	730 - 1,009
Santa Cruz	1,243 - 2,168	1,243 - 2,168	999 - 2,099	999 - 2,091
Santa Maria	2,085 - 5,723	2,085 - 5,326	2,094 - 5,783	2,075 - 5,622

1. Refer to Section V.D.3 for greater detail on the relative magnitude and location of the various emission sources contributing to the total emissions presented for each transportation scenario.

Table A-67. MAXIMUM ANNUAL SULFUR OXIDE EMISSIONS ASSOCIATED WITH LEASE SALE NO. 53 OIL AND GAS DEVELOPMENT - TONS PER YEAR

(LOW RESOURCE ESTIMATE - HIGH RESOURCE ESTIMATE)[1]

Proposed Zone	Transportation Scenario 1	Transportation Scenario 1-A	Transportation Scenario 2	Transportation Scenario 3
Eel River	134 - 367	134 - 367	134 - 367	134 - 367
Point Arena	499 - 970	499 - 970	499 - 970	256 - 636
Bodega	49 - 133	49 - 133	49 - 133	49 - 171
Santa Cruz	84 - 637	84 - 637	78 - 828	79 - 702
Santa Maria	231 - 1,789	231 - 1,789	399 - 3174	262 - 2302

1. Refer to Section V.D.3 for greater detail on the relative magnitude and location of the various emission sources contributing to the total emissions presented for each transportation scenario.

Table A-68. MAXIMUM ANNUAL CARBON MONOXIDE EMISSIONS ASSOCIATED WITH LEASE SALE NO. 53 OCS OIL AND GAS DEVELOPMENT - TONS PER YEAR

(LOW RESOURCE ESTIMATE - HIGH RESOURCE ESTIMATE)[1]

Proposed Zone	Transportation Scenario 1	Transportation Scenario 1-A	Transportation Scenario 2	Transportation Scenario 3
Eel River	75 - 280	75 - 280	75 - 280	75 - 280
Point Arena	190 - 384	193 - 384	190 - 384	188 - 382
Bodega	134 - 225	134 - 225	134 - 225	134 - 205
Santa Cruz	244 - 488	244 - 488	193 - 475	193 - 474
Santa Maria	402 - 1,149	402 - 1,094	399 - 1,120	398 - 1,113

1. Refer to Section V.D.3 for greater detail on the relative magnitude and location of the various emission sources contributing to the total emissions presented for each transportation scenario.

Table A-69. MAXIMUM ANNUAL TOTAL SUSPENDED PARTICULATE EMISSIONS ASSOCIATED WITH LEASE SALE NO. 53 OCS OIL AND GAS DEVELOPMENT - TONS PER YEAR

(LOW RESOURCE ESTIMATE - HIGH RESOURCE ESTIMATE)[1]

Proposed Zone	Transportation Scenario 1	Transportation Scenario 1-A	Transportation Scenario 2	Transportation Scenario 3
Eel River	16 - 70	16 - 70	16 - 70	16 - 70
Point Arena	67 - 131	67 - 131	67 - 131	54 - 122
Bodega	35 - 113	35 - 113	35 - 113	35 - 109
Santa Cruz	60 - 118	60 - 118	47 - 121	47 - 118
Santa Maria	106 - 356	106 - 356	112 - 420	105 - 344

1. Refer to Section V.D.3 for greater detail on the relative magnitude and location of the various emission sources contributing to the total emissions presented for each transportation scenario.

Table A-70. MAXIMUM ANNUAL HYDROGEN SULFIDE EMISSIONS ASSOCIATED WITH LEASE SALE NO. 53 OCS OIL AND GAS DEVELOPMENT - TONS PER YEAR

(LOW RESOURCE ESTIMATE - HIGH RESOURCE ESTIMATE)[1]

Proposed Zone	Transportation Scenario 1	Transportation Scenario 1-A	Transportation Scenario 2	Transportation Scenario 3
Eel River	12 - 28	12 - 28	12 - 28	12 - 28
Point Arena	14 - 35	14 - 35	14 - 35	14 - 35
Bodega	Neg.	Neg.	Neg.	Neg.
Santa Cruz	2 - 40	2 - 40	2 - 41	2 - 40
Santa Maria	11 - 105	11 - 105	11 - 105	11 - 105

1. Refer to Section V.D.3 for greater detail on the relative magnitude and location of the various emission sources contributing to the total emissions presented for each transportation scenario.

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APPENDIX B

DESCRIPTION OF MODELS

APPENDIX B. DESCRIPTION OF MODELS

A. Gaussian Models (CDM and PTMTP)

1. Methodology

There are two basic approaches to modeling point sources: statistical characterization and simulation. A commonly used point source methodology is called Gaussian. Gaussian procedures are statistically based and should normally be used only when the assumed conditions apply; these include requirements of flat terrain and steady unidirectional winds. Winds, however, are almost never steady and unidirectional over the coast. The methodology can be used, though, to define upper limits on estimated concentrations as part of a screening process for chemically inert pollutants. Source-receptor pairs can be quickly assessed to determine minimal emissions levels which will result in detectable concentration increments downwind. Slowly reacting pollutants, such as sulfur dioxide, can be assumed to be nonreactive. Modeling parameters, such as wind speed and atmospheric stability, are set to produce maximal levels for the screening.

The Gaussian methodology utilizes the normal, or Gaussian, distribution function to provide a fundamental solution to classic diffusion equations. In the Gaussian plume model, the crosswind plume concentration distributions are taken to be Gaussian in form. This has been partially substantiated through field experimentation during uniform meteorological conditions and for averaging times of one-quarter hour or longer. In the strict sense, the Gaussian diffusion model is valid only for these averaging times and for homogeneous, steady conditions. However, this type of model has been found to give useful results for many practical applications. A detailed discussion of the Gaussian diffusion model is given by Gifford (1968).

In its basic form, for a continuous point source at height h and a receptor at ground level, the Gaussian diffusion formulation is given by

$$\chi(x,y) = \frac{Q}{\pi\sigma_y\sigma_z u} \exp\left[-\left(\frac{y^2}{2\sigma_y^{\,2}} + \frac{h^2}{2\sigma_z^{\,2}}\right)\right]$$

where χ is the time-averaged ground-level concentration at horizontal coordinates (x,y), Q the continuous source strength, u the time-averaged magnitude of the wind velocity in the x direction (considered constant and unidirectional over the height interval between the plume and the ground), and σ_y and σ_z the standard deviations of the concentration distribution in the y (crosswind) and z (vertical) directions. These latter variables are usually taken to be functions of downwind distance x in the forms

$$\sigma_y = ax^b$$

and

$$\sigma_d = cx^d$$

where the constants, a,b,c, and d depend upon atmospheric stability and are derived empirically.

The point-source formula can be integrated in one or two dimensions to give linear area-integral representations. Generally both point- and area-source versions of the Gaussian formulation are used. In practice, the contributions of each source to the concentration at a given receptor is usually calculated separately and then added to give the total concentration. This superposition capability adds flexibility and is an important advantage of the Gaussian technique, in addition to its inherent simplicity, ease of use, and short computational times.

The basic disadvantages of the Gaussian plume approach are:

- Concentrations are not time-dependent in the usual sense (the approach is "quasi-steady-state" with input variables and computed concentrations updated, say, once per hour);
- Spatial variability in the meteorological parameters are difficult to incorporate;
- Difficulties are encountered when the wind is light and poorly defined in terms of direction and speed; and
- The approach cannot be used for reactive or secondary pollutants, because of inherent nonlinearities of chemical reactions.

The Gaussian model is often used to analytically obtain computed concentrations. The usual procedure for hand computations is to rely on Turner's "Workbook of Atmospheric Dispersion Estimates" (1970). Simple computer applications include the Environmental Protection Agency (EPA) PT-series, which includes the PTMTP (PoinT, MulTiple Point) model, and the models, PTMAX and PTDIS.

The assumptions that are made in PTMTP are as follows. Meteorological conditions are steady-state for each hour so that a Gaussian plume model is applicable to determine ground-level concentrations. Computations are performed in accord with Turner's "Workbook." The dispersion parameter values used for the horizontal dispersion coefficient, σ_y, and the vertical dispersion coefficient, σ_z, are those given in Figures 3-2 and 3-3 of the Workbook. The sources and receptors are assumed to exist in either flat or gently rolling terrain, and the stacks are tall enough to be free from building turbulence so that no aerodynamic downwash occurs. The wind speed and wind direction apply from the shortest to the tallest plume height. No wind direction shear or wind speed shear occurs. The given stability exists from ground-level to well above the top of the plume.

A more complex application of the Gaussian methodology is the Climatological Dispersion Model (CDM). The CDM model is used to compute long-term (monthly, seasonal or annual) quasi-stable pollutant concentrations at any ground level receptor using average emission rates from point and area sources and a joint frequency distribution of wind direction, wind speed, and stability for the same period. The model repeatedly calculates a series of Gaussian plumes for a statistical set of meteorological inputs and averages the results as a long-term average. Statistically complete inputs are required. The modeling approach used in CDM is based upon observations for short-term averages of plume concentrations in an urban context. For use in this study, results were extended to apply for long-term

averages in a less dispersive "rural" context.

The adaptation for rural conditions is as follows. Gaussian model dispersion coefficients which describe the rate of dispersion of a plume in the horiztontal (σ_Y) and vertical (σ_Z) directions for a rural environment are simulated. The methodology consists of shifting the stability classes towards more stable classifications to account for less turbulence from lack of urban structures and heat island effects. For example, Pasquill urban stability class C is shifted to class D to represent a rural value. As a result, the least plume dispersion which the model will allow, is equivalent to Pasquill rural stability class G.

There has been little validation of the CDM procedures. The authors of CDM acknowledge the limitations of the methodology and provide a means for, in essence, applying a universal fudge factor. The calculated average can be shifted to agree with an observed long-term average. Then, assuming that the modeling errors will be consistently corrected by this methodology for other inputs (different amounts or locations of emissions), new modeling cases which are variations of a calibration case can be computed and concentrations normalized against the observed data.

2. Accuracy and Sensitivity

There have been frequent statements made that the Gaussian methodology is accurate to within a factor of two or three. This view is given credence in some EPA dispersion model programs which print out the message "Concentration estimates (from the program) may be expected to be within a factor of three for (certain specified conditions)." The justification for such optimism appears to be Pasquill's sensitivity assessment of the Gaussian dispersion equation (1974). Pasquill assumed that the source emission rate, wind velocity and stability class were known exactly. Pasquill also assumed that the emissions height and the dispersion coefficients were accurate to within 15 percent. On the basis of those assumptions, Pasquill determined that measured vs. observed short-term average concentrations would vary by no greater than a factor of two.

Pasquill's sensitivity analysis was based upon assumptions as to the accuracy of some of the inputs. His sensitivity analysis does not translate into a prediction of accuracy for specific applications of Gaussian modeling. In general, inputs are not known with an accuracy comparable to Pasquill's assumptions. In particular, the stability class and the wind velocity are usually not known exactly at the plume height. More importantly, they are seldom constant for the entire distance from the source to the receptor. This condition is required to derive the Gaussian formulation from the general diffusion equations.

The range of accuracy in model applications for short-term averages is presently unknown. Discussions in the literature on the validation of short-term Gaussian modeling point to a wide range of accuracy in modeling efforts. More precise determinations of the accuracy of Gaussian models cannot be made until rigorous validation studies are completed.

There has been no rigorous validation of the CDM model, nor any proof, beyond arguments of plausibility, that multiple Gaussian computational modeling is consistent with simple Gaussian modeling. To test the compatibility, an approved Environmental Protection Agency (EPA) short-term Gaussian model was run and the results were summed in a CDM-mode. The results differed by an order of magnitude when compared with CDM. It has not yet been determined whether the

poor comparison resulted from errors in the computer codes or from problems in extending the short-term Gaussian formulation to computation of long-term averages.

The CDM model was implemented and used on the FAS IM-1 Air Pollution Modeling Micro-computer (Sklarew, 1979). The consistency of the modeling is verified to the degree of confirming that the model performed as specified on EPA-provided test data.

B. Simulation Models (IMPACT, RAPT)

There are two simulation methodologies available for the modeling of point sources. They differ in the way they keep track of each section of the downwind plume. The Lagrangian formulation follows each segment of the plume in space and time. As each segment, or cell, encounters background emissions and meteorological conditions, they are introduced into the computation of chemical reactions, diffusion, and transport. An example is the RAPT model which is used extensively in this study. A description of the model and its use can be found in Section 2., below. The Eulerian formulation relies on a grid fixed in space. Pollutants are tracked as they progress through the grid. Within each grid cell the constituents of a plume react with ambient air pollutants and with any emissions from other sources which enter the cell. An example of this type of modeling is the IMPACT model.

The simulation, with either formulation, is mathematically described first as a set of computer algorithms. A balance is struck between accuracy of computation and the number of computational steps and computer data storage requirements. Various computational systems have been developed. The most commonly used is called finite difference. Almost all methodologies require the definition of cells. Small cells result in greater resolution and accuracy, but make greater computer demands.

In the OCS environment, the study area has dimensions of tens of miles, or more. Grid cells with dimension of about one mile on a side are computationally feasible with the Eulerian formulation. The Lagrangian formulation requires fewer cells to define just the cross-wind direction. Additionally, the RAPT model allows variable cell sizes. (The structure of RAPT is a crosswind wall of cells moving with the wind.) Cells along the plume axis were given a width of 100 meters. The wall was given a total width of 5 kilometers. This grid configuration allows the detailed resolution of the structure of a single emission plume or the simulation of a sweep through an OCS zone.

During simulation, the emissions are entered into a first grid cell and are averaged over the grid cell; and, at each computational time step, emissions are transported into adjacent cells. The treatment of diffusion in the model can have a significant bearing on the simulated impacts downwind. The model must carefully consider horizontal and vertical diffusion, transport, chemistry, and time-varying wind fields.

Modeling cannot spatially resolve an impact to better than a few cells. Therefore, closely spaced emission sources may be lumped together in the same cell. Emissions can be updated for each time step and their impacts calculated with available ambient meteorological and air quality baseline data. A one hour time step was used in this study since short-term Ambient Air Quality Standards are most often defined in terms of one hour time periods. Temporal resolution

will be on the order of one to two hours.

1. Modeling Strategies

There are two modeling options which are applicable to reactive OSC emissions assessment. The first involves a trajectory analysis, where the plume trajectory is followed as far as the maximum ozone or population center. Emission sources can be analyzed individually or, more appropriately, as a summation of plumes along the trajectory. RAPT is such a model used in this study.

Alternatively, the emissions and reaction products can be followed within a full three-dimensional grid of the OCS and onhsore region. Emissions from OCS activities as well as non-OCS ones can be introduced directly into the appropriate gridded cells of the regional model. IMPACT is such a model used in this study.

In summary, RAPT focuses on specific emissions and by reason of the trajectory formulation overestimates their impact due to neglect of wind shear. IMPACT focuses on regionwide air quality and can only poorly resolve specific emissions. This results from inherently coarse cell resolution in applying the model. Thus, IMPACT will underestimate OCS impacts.

In using either approach, the same case (meteorology and air quality conditions) is run first without and then with OCS emissions. Subtraction of calculated ozone values from the two runs gives resultant ozone from the projected OCS emissions event for a given set of meteorological and air quality conditions.

The impact of future air pollution emissions is determined by their interaction with future ambient air quality conditions. Therefore, it is necessary to forecast future air quality. There are two approaches. The air quality maintenance planning approach begins with predictions of emissions trends and involves the forecasting of detailed future emissions from all sources (regionwide and OCS). This methodology can be described as assessing emissions standards through air quality modeling (additional details are given below, as part of the discussion of calibration and baselines). The second methodology emphasizes meeting the more fundamental federal- and state-mandated Ambient Air Quality Standards, rather than the emissions standards. Meeting the Ambient Air Quality Standards is scheduled in the State Air Quality Implementation and Maintenance Plans. Given this approach, future OCS emissions can be assumed to enter a region that meets the Ambient Air Quality Standards and the ambient or background pollutant levels can be assumed to be no greater than those mandated. This latter approach can be executed in two ways: either (1) emissions can be further adjusted to result in a baseline run which meets the Ambient Air Quality Standards; or (2) emissions can be ignored entirely and the baseline air quality can be directly "adjusted." The methodology may be conservative to the degree that the OCS emissions are conspicuous if, regionwide, the Ambient Air Quality Standards are assumed to have been met. The difference between the two is minimal if the air quality maintenance plan meets its objective. The former approach is used in this study.

2. Reactive Air Pollutant Transport Model (RAPT)

The Reactive Air Pollutant Transport Model (RAPT) is based on solving equations that describe the conservation of mass for reacting air pollutants in a two-dimensional, cross-wind Lagrangian plane of cells. The model simulates advection by movement of the cells, diffusion in vertical- and cross-wind

horizontal directions by cellular finite differencing, source emissions by time-phased pollutant additions, and chemical reactions by the appropriate chemical rate equations calculated for each cell. Thus, RAPT calculates the physical and chemical evolution of a "wall" of air.

Since RAPT focuses on a cross-wind plane, it is ideal for calculating the impact of a localized (or point) emission source or for evaluating changes in air quality across a region. For the former, the calculation of horizontal and vertical diffusion is very important. For the latter, temporally and spatially varying emissions are required. In either case, the two-dimensional RAPT approach offers cost-effective calculations which maintain the significant physics simulated in the largest photochemical models but requires only a fraction of their computer resource needs.

RAPT has been successfully applied to assessing effects of reactive emissions from point sources in the Ventura, Santa Barbara and San Francisco areas and to regional air quality in San Diego County as well as to southern California OCS developments.

Since RAPT has not yet been thoroughly documented in the literature, the following section briefly presents the genealogy of RAPT from its predecessors, IMPACT and MADCAP, the methodologies used in RAPT and the data requirements for its application.

a. RAPT Genealogy

RAPT is a model which merges the techniques used in IMPACT (Integrated Model of Plumes and Atmospherics in Complex Terrain) and MADCAP (Model of Advection, Diffusion and Chemistry of Air Pollution). RAPT uses the diffusion treatment from IMPACT and the advection and chemistry methods of MADCAP. It has extended the previous algorithms by employing variable cell sizes for higher resolution of plume impacts. The RAPT model has the time-saving Lagrangian features of MADCAP and the superior diffusion algorithms of IMPACT, as well as greater resolution.

b. Model Structure and Methodology

i. Equations

The equations that describe conservation of mass for reacting pollutants are coupled, nonlinear, first-order, partial differential equations of the form:

$$\frac{\partial c_i}{\partial t} = -\nabla \cdot u c_i + \nabla \cdot K \cdot \nabla c_i + S_i + R_i$$

where

c_i is the concentration of the ith species

u is the wind velocity

K is the tensor diffusivity

S_i is the source rate for the ith species

R_i is the net rate of change of the ith species due to chemical reactions

The equations describe the time rate of change of the ith species concentration at a location as resulting from the sum of the inward transport of species i to the location, the increase of species i at the location through diffusion, the emissions of species i by sources at the location and the net increase from chemical formation and removal of species i.

a) Uniform Wind Assumption

The RAPT model assumes a uniform wind speed throughout the wall of cells (refers to the first term in the equations). Except in complex terrain areas, the concept of a mean wind has proven useful in describing pollution transport. Although the actual wind field may have significant directional and speed shear in both the vertical and horizontal directions, operationally, there rarely exists sufficient data to document the variations. In addition, photochemical models are mainly used for examining potential future worst-case impacts; these are applications for which detailed winds cannot be known. The RAPT model takes into account these imprecisions. In summary, RAPT computes concentrations along a trajectory of uniformly moving air and simulates transport of pollutants within the moving air by Lagrangian cell motion.*

b) Diffusion Calculations

The diffusion term is simulated by finite differencing in the vertical and crosswind directions over an atmospheric "wall" of cells. Diffusion in the downwind direction is considerably less important for continuous emissions than advective mass transport and so is dropped without affecting the overall accuracy of the model. The finite difference grid for calculating diffusion is variably zoned for increased accuracy near the center of the plume (i.e., central and lower cells have smaller width and height than lateral and upper cells).

c) Chemical Calculations

The last term in the equations is calculated by a chemical rate equation based on an assumed chemical mechanism (or set of reactions and rate constants) such that:

$$R_i = f_i - r_i c_i$$

where

f_i is the rate of formation of species i

$r_i c_i$ is the rate of removal of species i

The governing partial differential equations are solved by using the method of fractional steps (Yanenko, 1971). The equations are solved sequentially for diffusion and chemistry in a cyclical manner.

*Simple extensions of RAPT would permit simulation of moderate wind shear. However, lacking applications requirements and the detailed data for exercising this feature, RAPT has taken the simplest form which achieves the desired purpose.

ii. Turbulent Diffusion Simulation

The turbulent diffusion process is treated in RAPT using first-order K-theory. The horizontal and vertical diffusivities are calculated with the DEPICT method, as described below. The implicit finite-difference technique is used to solve the diffusion term.

a) Eddy Diffusivities Calculation

The eddy diffusivities are calculated by Subroutine DIFCOF. The algorithm used is that of the DEPICT model (Sklarew, 1977).

The vertical diffusivity is calculated from:

$$D_V = (.45)\ \overline{U}\ \sigma_\varepsilon \ell$$

In this equation, $\overline{U}$ is the wind speed at the point of interest; σ_ε is the (measured or estimated) standard deviation of the wind vane fluctuation, with σ_ε empirically related to stability as follows:

Stability	1	2	3	4	5	6
σ_ε	0.262	0.237	0.184	0.119	0.056	0.023

and ℓ is the turbulence length scale [in meters (m)] and is empirically related to height above the ground and stability as follows:

Stability	1	2	3	4	5	6
ℓ @ 100m	105	85	74	64	59	54
ℓ @ 10m	18	15	12	10	8	7

The horizontal diffusivities are calculated using the relation $D_H = \alpha D_V$ where D_V is described above, and α depends on stability as follows:

Stability	1	2	3	4	5	6
α	0.5	0.75	1.05	1.35	1.70	2.0

b) Numerical Solution

The effect of horizontal and vertical diffusion on concentrations is simulated by Subroutine DIFUS. The diffusion equation is solved separately for the horizontal direction and the vertical direction. The fundamental equation to be solved by each call to Subroutine DIFUS is:

$$\frac{\partial C}{\partial t} = \frac{\partial}{\partial X_j} \left(K_j \frac{\partial C}{\partial X_j} \right)$$

where

x_j is either x_2 (equivalently, y, the cross-wind coordinate) or x_3 (equivalently, z, the vertical coordinate)

K_j is the diffusivity in the j-direction

The above equation is converted into discrete form by using fully implicit finite differences:

$$\frac{C_i^{n+1} - C_i^{n}}{\Delta t} = \frac{1}{\Delta x_i} \left[\frac{K_i \Delta X_{i+1} + K_{i+1} \Delta X_i}{\Delta X_{i+1} + \Delta X_i} \right] \frac{C_{i+1}^{n+1} - C_i^{n+1}}{(\Delta X_i + \Delta X_{i+1})/2} - \left[\frac{K_{i-1} \Delta X_i + K_i \Delta X_{i-1}}{\Delta X_{i-1} + \Delta X_i} \right] \frac{C_i^{n+1} - C_{i-1}^{n+1}}{(\Delta X_{i-1} + \Delta X_i)/2}$$

where the superscript n denotes the time step and the subscript i the nodal point.

The resulting system of linear equations has a tridiagonal coefficient matrix; and an efficient recursive algorithm has been used to solve the system of equations.

iii. Source Simulation

Source emissions are entered into the calculation as the "wall" of air passes over them along its trajectory. Each added source may be detailed individually. In most applications, however, the sources are inventoried and apportioned to a grid.

iv. Photochemical Kinetics Simulation

The effects of chemical reactions in each cell are calculated for a time period which is determined by the rate of change of pollutant concentrations through nonchemical processes (e.g., emissions and diffusion). A time step is typically five to ten minutes. The chemical mechanism presently used is the LIRAQ-2 mechanism.

LIRAQ-2 is an updated photochemistry developed by Lawrence Livermore Laboratory (Gelinas, 1977) and used by Form & Substance, Inc., in successful photochemical modeling in the San Diego Air Basin (Sklarew, 1978a, 1978b). The species and chemical reactions of the LIRAQ-2 mechanism are shown in Table B-1. Since the grid is Lagrangian, calculating costs do not increase directly in proportion to the number of species in the chemistry and, therefore, large chemical equation mechanisms are feasible.

Subroutine CHEMC is the chemical module of RAPT. It is designed to simulate the complex chemical transformations of air pollutants by using the photochemical kinetics mechanism given in Table B-1. This mechanism, known as LIRAQ-2, employs three hydrocarbon species; a preliminary sulfur dioxide reaction set is also included.

In this photochemical model, there are <u>17 active species</u> (NO_2, NO, O_3, HCl, HC2, HC3, N_2O_5, HNO_3, HNO_2, RNO_2, H_2O_2, CO, RO_2, RCO_3, SO_2 and SO_4) and <u>four species in quasi-equilibrium</u> (O, HO, NO_3 and RO). At the present time, the conversion of sulfur dioxide (SO_2) to sulfates (SO_4) is not computed and, therefore, the mechanism encoded in CHEMC consists of 15 active species (the sulfur oxidation chemistry in LIRAQ-2 has been insufficiently tested and was,

Table B-1. LIRAQ-2 Photochemical Kinetics Mechanisms

STEP	REACTION	A - CONSTANTS -	C
1	NO2+ hν = NO+O	1.2E-2	
2	HNO2+hν = HO+NO	7.2E-4	
3	H2O2+hν = HO+HO	5.5E-6	
4	NO3+hν = NO2+O	2.8E-3	
5	O3+hν = O2+O	5.1E-4	
6	O3+hν+H2O = 2HO+O2	2.2E-5	
7	RNO2+hν = RO+NO	1.9E-3	
8	HC3+hν = HO2+HO2+CO	2.7E-5	
9	HC3+hν = RO2+HO2+CO	2.7E-5	
10	O2+O+ZM=O3+ZM	1.0E-34	-510.
11	O3+NO = NO2+O2	9.0E-13	1200.
12	O+NO+ZM=NO2+ZM	4.0E-33	940.
13	O+NO2 = NO+O2	9.1E-12	
14	O+NO2+ZM = NO3+ZM	3.5E-32	-300.
15	O3+NO2 = NO3+O2	1.1E-13	2450.
16	NO2+NO3 = N2O5	3.8E-12	
17	N2O5 = NO2+NO3	5.7E-14	10600.
18	NO3+NO = NO2+NO2	8.7E-12	
19	N2O5+H2O = HNO3+HNO3	3.0E-16	3300.
20	HO+NO2 = HNO3	7.0E-12	
21	HO+NO = HNO2	7.0E-12	
22	HO2+NO = HO+NO2	2.0E-13	
23	HO2+NO2 = HNO2+O2	3.0E-14	
24	HO+HNO3 = H2O+NO3	1.3E-13	
25	HO2+HO2 = H2O2+O2	3.0E-12	
26	HO2+HO = H2O+O2	2.0E-11	
27	HO+CO = HO2+CO2	1.4E-13	
28	HC1+O = RO2+.5RCO3+.5HO2	1.0E-11	360.
29	HC1+O3 = HO2+RO+HC3	7.0E-15	1900.
30	HC1+O3 = Ozonide	7.0E-15	1900.
31	HC1+HO = RO2+HC3	5.0E-11	350.
32	HC1+HO = RO2+H2O	3.0E-11	350.
33	HC2+O = RO2+HO	4.1E-11	2000.
34	HC2+HO = RO2+H2O	4.0E-11	900.
35	HC3+O = HO+HO2+CO	4.0E-12	900.
36	HC3+HO = RCO3+H2O	3.0E-11	350.
37	HC3+HO2 = H2O2+RCO3	8.0E-13	3700.
38	HC3+NO3 = HNO3+RCO3	3.0E-15	900.
39	HC3+HO = CO+HO2+H2O	3.0E-11	350.
40	HC3+NO3 = CO+HNO3+HO2	3.0E-15	650.
41	HC3+RO2 = RHO2+RCO3	8.0E-13	3750.
42	RO2+NO = RNO3	0.0E-00	
43	RO2+NO = RO+NO2	5.0E-12	300.
44	RCO3+NO = RO2+NO2+CO2	6.5E-12	600.
45	RCO3+NO2 = PAN	3.04E-14	
46	RO+NO2 = RNO3	5.0E-14	
47	RO+NO = RNO2	5.0E-14	
48	RO+O2 = HO2+HC3	1.6E-13	3300.
49	RO2+RO2 = RO+RO+O2	6.7E-14	

Table B-1 (Continued).

		A	C
50	RO2+HO2 = RO+HO+O2	6.7E-14	
51	SO2+RO2 = RO+SO4	2.0E-15	
52	SO2+RO = HO2+SO4	4.0E-13	
53	SO2+HO2 = HO+SO4	9.0E-16	
54	SO2+HO+ZM = HO2+SO4+ZM	2.4E-32	
55	SO2+O+ZM = SO4+ZM	3.4E-32	1130.
56	SO2+RCO3 = RO2+SO4	1.03-15	
57	HNO3+hν = HO+NO2	4.9E-7	
58	N2O5+hν = NO2+NO2+O	2.9E-5	

Notes:

Rate Constant of the Form: K=Aexp (-C/T) in units of $m^{-3}sec^{-1}$

Dynamic Species: NO2, NO, O3, HC1, HC2, HC3, N2O5, HNO3, HNO2, HO2, RNO2, H2O2, CO, SO2, SO4

Non-Accumulating Species: RO_2, RCO3

Quasi-Equilibrium: O, HO, NO3, RO

HC1 - aliphatic olefins

HC2 - alkanes, cycloparaffins, less reactive aromatics and oxygenates

HC3 - aldehydes and ketones

Source: Gelinas, 1977

therefore, eliminated.)

CHEMC solves a system of nonlinear equations of the following form:

$$\frac{\partial C_i}{\partial t} = \sum_{k,j} R_{ikj} C_k C_j + S_i$$

where C_i is the concentration of active species i, with indexes ranging from 1 to N. The above equations are recast in the following form:

$$\frac{\partial C_i}{\partial t} = A_i - B_i C_i$$

where A_i is the production rate of species i (chemical formation, source emissions and diffusion into the cell), and $B_i C_i$ is the removal rate of species i (chemical reactions and diffusion out of the cell).

Solution of the above system of first-order ordinary differential equations is by an exponential predictor-corrector method. This method is based on the analytical prediction of concentration of a short time later (Δt), given by

$$C_i\ (t+\Delta t) = \frac{A_i}{B_i} + [C_i(t) - \frac{A_i}{B_i}] \quad - B_i \Delta t$$

v. Program Logic

Figure B-1 illustrates the RAPT program logical flow. The computations in the program modules are described in previous subsections. Data requirements are described below in Section B.2.2.

c) Data Requirements

In most applications, RAPT is used to evaluate the photochemical production of oxidants resulting from a localized source of reactive pollutants (typically nitric oxide and hydrocarbons) as the emissions move and react with other pollutants. First, one or more trajectories are developed. Meteorological and air quality data are reviewed for days with high ozone levels. These days are indicative of worst case conditions: low wind speeds and inversion heights, high insolation (sunlight), and high entrainment of pollutants. Wind directions are analyzed for potential trajectories between the proposed emission source and potential receptors (defined at least in part by monitoring locations). Trajectories are usually constructed backwards in time from the field of wind monitoring data. The selection process is simplified if high pollutant trajectory analyses are available. Then, air quality data for the initial hour are collected or estimated. Next, a baseline calibration is established. This consists of running the model for established conditions and comparing results with measurements of concentrations. Baseline calibrations for ozone and nitrogen dioxide (NO_2) for each trajectory are presented at the end of this section. If a future event is involved, air quality conditions are projected forward in time. Then, the emissions being assessed are added to the initial conditions of the pollutants in the RAPT grid at the point where they are emitted (including plume rise). The variable grid

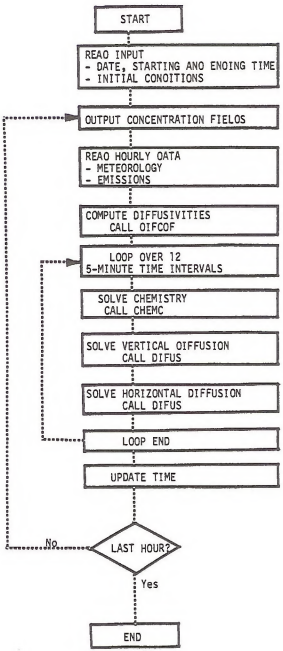


Figure B-1. RAPT Program Logic

formulation allows detailed resolution of the highly concentrated emissions plume at a reasonable computer cost. As the grid moves, it sweeps over other emissions which are added to the modeling cells at the appropriate location and time. In this way, the effects of region-wide emissions can be calculated and evaluated.

The required input data consists of (1) initial pollutant concentrations (e.g., HCl, HC2, HC3, NO, NO_2, CO and O_3) including any initial emission; (2) other varying emissions encountered as the Lagrangian grid moves; (3) time-varying insolation (sunlight) that drives the photochemical reactions; and (4) time-varying wind speed, atmospheric stability and inversion height needed to calculate the diffusivities.

3. Integrated Model of Plumes and Atmospherics in Complex Terrain (IMPACT)

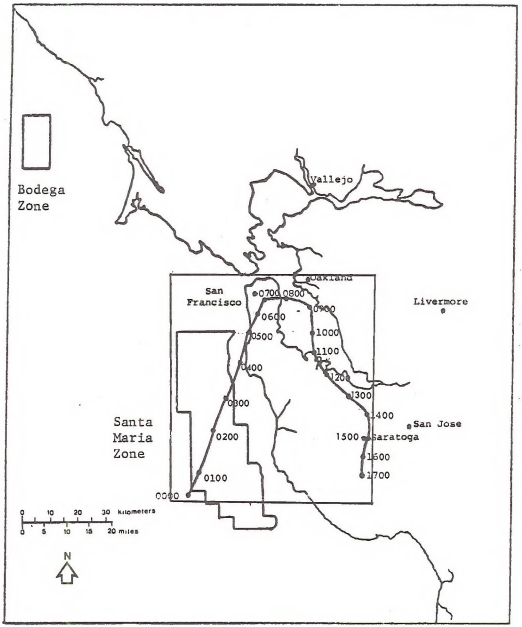
The Integrated Model of Plumes and Atmospherics in Complex Terrain (IMPACT) is based on solving equations that describe the conservation of mass for reacting air pollutants in a full three-dimensional grid of cells covering a region. Some of the techniques used are described above. IMPACT is fully documented in Point Source Modeling by Fabrick, Sklarew and Wilson (Form & Substance, 1977).

IMPACT has been used extensively for reactive emissions assessments by Form & Substance, Inc., Southern California Edison, the California Air Resources Board (under the model name SMOG), and others. IMPACT was also used to simulate the potential impacts of OCS Lease Sale No. 53 activities. The meteorology and air quality for August 5, 1979, as described by Bay Area Trajectory No. 6 (Figure IV-14) was chosen for IMPACT simulation.

The grid used in the simulation covers an area of 70 km, east to west, by 85 km, north to south, and is shown in Figure B-2. The grid is divided into 14 by 17 square cells, each 5 kilometers on a side, to be consistent with the Bay Area Air Quality Management District (BAAQMD) emission inventory and previous LIRAQ modeling. There are three layers of cells in the vertical direction, each 150 meters high.

IMPACT computes pollutant transport through use of a generated, mass-consistent wind field. The wind field takes into account terrain effects, measured winds and stability data. The terrain data were digitized from a terrain map generated by Lawrence Livermore Laboratory. The digitized terrain is displayed in Figure B-3. All available meteorological data were used as inputs to the model. The trajectory data from RAPT (wind speeds, directions and locations) were als incorporated into the IMPACT simulation to insure that the emissions trajectory, using IMPACT, would be similar to the one in the RAPT simulations and would also result in passage of the plume into the South Bay area.

The insignificant impacts predicted by IMPACT simulation (refer to Ch. VI.C.6.d.) grid cell size (5 km), the low wind speed (average wind speed was 5 mph) and the low inversion height (average mixing height was 120 meters) persistent throughout the day. The IMPACT grid is consistent with regional modeling and is the same used by the BAAQMD. These meteorological conditions tend to produce wind fluctuations and shears that rapidly disperse emissions.



[Numbers along trajectory - e.g. 0500 - refer to time (PST) of day]

FIGURE B-2. IMPACT GRID AREA

TERRAIN HEIGHT PRINT (M)

MULTIPLIER= 1.00000E+01 =10

I=	1	2	3	4	5	6	7	8	9	10	11	12	13	14
J= 17	0	0	0	0	0	0	0	0	0	0	15	20	25	40
J= 16	0	0	0	0	0	0	0	0	0	0	0	15	20	25
J= 15	0	0	0	0	0	10	0	0	0	0	0	0	15	30
J= 14	0	0	0	0	0	10	0	0	0	0	0	0	10	30
J= 13	0	0	0	0	0	15	10	0	0	0	0	0	0	15
J= 12	0	0	0	0	10	30	20	0	0	0	0	0	0	0
J= 11	0	0	0	0	0	20	25	10	0	0	0	0	0	0
J= 10	0	0	0	0	0	0	20	25	20	0	0	0	0	0
J= 9	0	0	0	0	0	0	15	40	25	10	0	0	0	0
J= 8	0	0	0	0	0	0	10	30	30	25	15	10	0	0
J= 7	0	0	0	0	0	0	0	15	30	40	50	30	10	0
J= 6	0	0	0	0	0	0	0	15	22	30	60	50	20	10
J= 5	0	0	0	0	0	0	0	15	30	35	45	55	50	35
J= 4	0	0	0	0	0	0	0	15	30	40	40	45	55	40
J= 3	0	0	0	0	0	0	0	10	20	40	45	40	40	40
J= 2	0	0	0	0	0	0	0	0	10	35	55	30	30	35
J= 1	0	0	0	0	0	0	0	0	0	0	40	35	25	25

(I = West to east cell numbers)

(J = South to north cell number)

Figure B-3. DIGITIZED TERRAIN HEIGHT IN METERS OF THE IMPACT GRID

It was anticipated, before modeling, that RAPT would result in higher onshore concentrations than would be produced using IMPACT. There are two reasons why IMPACT should result in lower computer concentrations. First, the large trajectory distances and the LIRAQ modeling precedent called for IMPACT cells much larger (5 km by 5 km by 150 m) than RAPT cells (as small as 100 m wide by 100 m high along the plume centerline). Emissions, upon release, are necessarily diluted into the first cell; and the amount of dilution limits concentration computed downwind.

Second, terrain can impede the flow of pollutants inland or can shear the plume apart through turbulence effects. They both occurred in this simulation. Increasing the wind speed and inversion height would have lessened terrain effects, but would also have augmented dilution of the plume.

C. References

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APPENDIX C

MODELING INPUTS

APPENDIX C. MODELING INPUTS

Tables C-1 through C-25 describe emissions scenarios which were prepared for modeling purposes. These tables are based on the emissions inventories in Chapter V and the source data used in preparing that chapter. Tables C-1 through C-30 do not describe actual modeling inputs (the modeling inputs can be found in Tables C-38 through C-42). Rather, they are a compendium of worst case and average emissions which cover averaging periods of one-hour through one-year. For each zone and each pollutant, highest emissions years are described in the data and in the footnotes.

For each zone, the first table represents the year with highest hydrocarbon emissions. Associated nitrogen oxides emissions used in photochemical modeling are also given (see Section C of Chapter VI for a description of the modeling and of modeling results). The second in each group of tables gives nitrogen oxides (NO_x) emissions for the peak NO_x emissions year. These NO_x values do not correspond to those in the first table since the events and years described differ.

The remaining tables for each zone give appropriately averaged peak emissions of sulfur oxides, suspended particulate matter, and carbon monoxide. Tables C-25 through C-30 describe non Lease Sale No. 53 offshore emissions in Santa Barbara Channel. These emissions were used in defining the present and future baselines for the Goleta trajectory from the Santa Maria OCS zone around Point Conception and into Goleta (refer to Figure IV-21). These emissions were abstracted from the AeroVironment study for Lease Sale No. 48 (1977).

Figures C-1 through C-4, Table C-31, and Tables C-33 through C-37 summarize the modeling inputs for computing annual averages with the CDM model (Table C-32 is analogous to Table C-31, but is used for one-hour average modeling). Figures C-1 through C-4 display joint frequency meteorology used in the modeling. The model and modeling input requirements are described in Appendix B. The modeling application is described in Section A of Chapter VI.

Table C-31 summarizes the stack parameters used in CDM modeling to compute effective plume heights for each of the meteorological regimes summarized in Figures C-1 through C-4. Tables C-33 through C-37 summarize emissions used in the CDM modeling, one for each Lease Sale No. 53 block. The Eel River, Point Arena, and Bodega computations assumed a geographical worst case by condensing all emissions into one point source. Tables C-33 through C-37 reference the emissions tables, described above, which were used in preparing the modeling emissions. Tables C-36 (Santa Cruz) and C-37 (Santa Maria) describe emissions in terms of individualized emissions points. These tables are keyed to map figures in Chapter VI.

Table C-32 describes stack parameters used in computing onshore one-hour average concentrations for worst case meteorology (wind speed of 2 meters per second and stable atmospherics). The methodology used in deriving the combination of stack parameters and meteorology is described in Section B of Chapter VI.

Table C-1. MAXIMUM HOURLY REACTIVE POLLUTANT EMISSIONS - EEL RIVER AREA[1]
(lbs/hr)

Source/Activity	Type[2]	Scenario[1] HC	Scenario[1] NO_x	Scenario 1A HC	Scenario 1A NO_x	Scenario 2 HC	Scenario 2 NO_x	Scenario 3 HC	Scenario 3 NO_x
A. Production Platform	S								
Development Drilling		0.5	6	0.5	6	0.5	6	0.5	6
Power Generation		3	35	3	25	3	35	3	35
Evaporative Losses		3	--	3	--	3	--	3	--
B. Floating Production System[4]	S								
Subsea Drilling		0.5	6	0.5	6	0.5	6	0.5	6
Power Generation		3	35	3	25	3	35	3	35
Evaporative Losses		56	--	56	--	56	--	56	--
Gas Processing		438	--	--	--	438	--	438	--
C. Supportive Activities									
Supply Boat[5]	S	2	63	2	63	2	63	2	63
	L	2	63	2	63	2	63	2	63
Crew Boat[6]	S	--	6	--	6	--	6	--	6
D. Onshore Gas Processing Plant[7]	S	--	--	438	21	--	--	--	--

Table C-1.(continued).

1. All values given are based upon the level of activity required in 1987 for maximum production.

2. The type of emission source refers to stationary (S), line (L), or area (A) sources.

3. It was assumed that there would be one production platform.

4. It was assumed that there would be one floating production platform.

5. Maximum hourly emissions were assumed to occur when two supply boats spend one-half an hour at the platform and one-half an hour in transit toward land. On an annual basis, it was assumed that 90 percent of pollutants from supply boats would be emitted while the source is mobile (line source) between the zone and Eureka. Approximately 10 percent of the pollutants were assumed to be emitted while the source is stationary; emissions would be distributed among the platforms.

6. Maximum hourly emissions were assumed to occur when one crew boat spends one-half an hour at the platform and one-half an hour in transit toward land. On an annual basis, it was assumed that 80 percent of pollutants from crew boats would be emitted while the source is mobile (line source) between the zone and Eureka. Approximately 10 percent of the pollutants were assumed to be emitted as a stationary source at the platforms or in port.

7. For Scenario 1A, the gas processing plant would be located about four miles inland.

Table C-2 MAXIMUM NITROGEN OXIDES EMISSIONS - EEL RIVER AREA[1]

Source/Activity	Type[2]	Scenarios 1, 1A, 2 and 3 lbs/hr	tons/yr
A. Platform Installation[3]			
Derrick Barge	S	69	180
Tugboats[4]	A	86	451
	S	86	--
Supply Boats[5]	L	10	26
	S	1	3
Crew Boats[6]	L	2	4
	S	0.2	0.4
B. Pipeline Installation[7]			
Tugboats[8]	L	172	27
Lay Barge	L	35	6
Jet Barge	L	124	12
Supply Boat[9]			
At Installation Site	S	6	2
In Transit	L	6	2
Crew Boat[10]			
At Installation Site	S	6	2
In Transit	L	6	2

1. All values given are based upon the level of activity required in 1985 for estimated peak construction activities.
2. The type of emission source refers to stationary (S), line (L), or area (A) sources.
3. One platform was assumed to be installed.
4. It was assumed that there would be 4 tugboats/platform installed. On an hourly basis, two were assumed to be stationary and two were assumed to be maneuvering in the general vicinity of the platform. On an annual basis, all four tugboats were assumed to be maneuvering near the platforms.
5. It was assumed that there would be one supply boat per platform installed. In the maximum hour case, it was assumed that the supply boat would be at the platform for one-half an hour and in transit for one-half an hour. On an annual basis, it was assumed that 90 percent of pollutants from the supply boat would be emitted while the source is mobile (line source) between the zone and Eureka. Approximately 10 percent of the pollutants were assumed to be emitted while the source is stationary at the platform.
6. It was assumed that there would be one crew boat per platform installed. In the maximum case, the crew boat was assumed to be at the platform for one-half an hour and in transit for one-half an hour. On an annual basis, the crew boat was assumed to be a line source from the zone to the nearest port with 10 percent of the total emissions occurring at each end of the route as a stationary source.

Table C-2 (continued)

7. It was assumed that there would be 13 miles of pipeline laid in a straight route to shore.
8. It was assumed that there would be one lay barge assisted by two tugboats and one jet barge, also assisted by two tugboats. The two barges would operate about two miles apart and would progress with the pipeline installation at the rate of one mile per day.
9. It was assumed that there would be one supply boat supporting pipeline installation. In the maximum hour case, it was assumed that the supply boat would be at a barge for one-half an hour and in transit for one-half an hour. On an annual basis, it was assumed that 90 percent of pollutants from the supply boat would be emitted while the source is mobile (line source) between the zone and Eureka. Approximately 10 percent of the pollutants were assumed to be emitted while the source is stationary at the installation site
10. It was assumed that there would be one crew boat supporting pipeline installation. In the maximum hour case, the crew boat was assumed to be at a barge for one-half an hour and in transit for one-half an hour. On an annual basis, the crew boat was assumed to be aline source from the zone to the nearest port with 10 percent of the total emissions occurring at each end of the route as a stationary source.

Table C-3. MAXIMUM SULFUR OXIDE EMISSIONS - EEL RIVER AREA[1]

Source/Activity	Type[2]	Scenarios 1, 2, and 3				Scenario 1A			
		lbs/hr	lbs/3 hrs	lbs/day	tons/yr	lbs/hr	lbs/3 hrs	lbs/day	tons/yr
A. Production Platform[3]	S								
Developmental Drilling		3	9	78	5	3	9	78	5
Power Generation		19	57	451	82	19	57	451	82
B. Floating Production System[4]	S								
Subsea Drilling		3	9	78	0.9	3	9	78	0.9
Power Generation		19	57	451	82	19	57	451	82
Gas Processing		22	66	533	97	--	--	--	--
C. Supportive Activities									
Supply Boats[5]									
At Platforms	S	2	2	3	0.3	2	2	3	0.3
In Transit	L	2	16	24	2	2	16	24	2
In Port	S	--	2	3	0.3	--	2	3	0.3
Crew Boats[6]									
At Platforms	S	2	0.3	0.5	Neg	2	0.3	0.5	Neg.
In Transit	L	2	3	4	0.2	2	3	4	0.2
In Port	S	--	0.3	0.5	Neg.	--	0.3	0.5	Neg.
D. Onshore Gas Processing Plant[7]	S	--	--	--	--	22	66	533	97

Table C-3 (continued)

1. All values given are based upon the level of activity expected in 1987 for maximum production.

2. The type of emission source refers to stationary (S), line (L), or area (A) sources.

3. It was assumed that there would be one production platform.

4. It was assumed that there would be one floating production system.

5. Maximum hourly emissions were assumed to occur when two supply boats spend one-half an hour at the platform and one-half an hour in transit toward land. On an annual basis, it was assumed that 90 percent of pollutants from supply boats would be emitted while the source is mobile (line source) between the zone and Eureka. Approximately 10 percent of the pollutants were assumed to be emitted while the source is stationary; emissions would be distributed among the platforms.

6. Maximum hourly emissions were assumed to occur when one crew boat spends one-half an hour at the platform and one-half an hour in transit toward land. On an annual basis, it was assumed that 80 percent of pollutants from the crew boat would be emitted while the source is mobile (line source) between the zone and Eureka. Approximately 10 percent of the pollutants were assumed to be emitted as a stationary source at the platforms or in port.

7. For Scenario 1A, the gas processing plant would be located about four miles inland.

Table C-4. MAXIMUM TOTAL SUSPENDED PARTICULATE EMISSIONS - EEL RIVER AREA[1]

Source/Activity[1]	Type[2]	Scenarios 1, 1A, 2 and 3 lbs/day	tons/yr
A. Platform Installation[3]			
Derrick Barge	S	100	11
Tugboats[4]	A	90	10
	S	90	10
Supply Boats[5]	L	10	0.8
	S	1	0.1
Crew Boats[6]	L	2	Neg.
	S	0.2	Neg.
B. Pipeline Installation[7]			
Tugboats[8]	L	180	1
Lay Barge	L	52	0.3
Jet Barge	L	183	0.7
Supply Boat[9]			
At Installation Site	S	1	Neg.
In Transit	L	10	0.1
In Port	S	1	Neg.
Crew Boat[10]			
At Installation Site	S	0.2	Neg.
In Transit	L	2	Neg.
In Port	S	0.2	Neg.

1. All values given are based upon the level of activity required in 1985 for estimated peak construction activities.
2. The type of emission source refers to stationary (S), line (L), or area (A) sources.
3. One platform was assumed to be installed.
4. It was assumed that there would be 4 tugboats/platform installed. On an hourly basis, two were assumed to be stationary and two were assumed to be maneuvering in the general vicinity of the platform. On an annual basis, all four tugboats were assumed to be maneuvering near the platform.
5. It was assumed that there would be one supply boat per platform installed. In the maximum hour case, it was assumed that the supply boat would be at the platform for one-half an hour and in transit for one-half an hour. On an annual basis, it was assumed that 90 percent of pollutants from the supply boat would be emitted while the source is mobile (line source) between the zone and Eureka. Approximately 10 percent of the pollutants were assumed to be emitted while the source is stationary at the platform.
6. It was assumed that there would be one crew boat per platform installed. In the maximum case, the crew boat was assumed to be at the platform for one-half an hour and in transit for one-half an hour. On an annual basis, approximately 10 percent of pollutants from the crew boat would be emitted while the source is mobile (line source) between the zone and Eureka. Approximately 10 percent of the pollutants were assumed to be emitted as a stationary source at the platforms or in port.

Table C-4 (continued)

7. It was assumed that there would be 13 miles of pipeline laid in a straight route to shore.
8. It was assumed that there would be one lay barge assisted by two tugboats and one jet barge, also assisted by two tugboats. The two barges would operate about two miles apart and would progress with the pipeline installation at the rate of one mile per day.
9. It was assumed that there would be one supply boat supporting pipeline installation. In the maximum hour case, it was assumed that the supply boat would be at a barge for one-half an hour and in transit for one-half an hour. On an annual basis, it was assumed that 90 percent of pollutants from the supply boat would be emitted while the source is mobile (line source) between the zone and Eureka. Approximately 10 percent of the pollutants were assumed to be emitted while the source is stationary at the installation site.
10. It was assumed that there would be one crew boat supporting pipeline installation. In the maximum hour case, the crew boat was assumed to be at a barge for one-half an hour and in transit for one-half an hour. On an annual basis, approximately 80 percent of the pollutants from the crew boat would be emitted while the source is mobile (line source) between the zone and Eureka. Approximately 10 percent of the pollutants were assumed to be emitted as a stationary source at the platforms or in port.

Table C-5. MAXIMUM CARBON MONOXIOE EMISSIONS - EEL RIVER AREA[1]

Source/Activity[1]	Type[2]	Scenarios 1, 1A, 2 and 3		
		lbs/hr	lbs/8 hrs	lbs/12 hrs
A. Platform Installation[3]				
Derrick Barge	S	13	104	157
Tugboats[4]	A	13	104	157
	S	13	104	157
Supply Boats[5]	L	0.4	3	5
	S	3	26	38
Crew Boats[6]	L	0.8	6	10
	S	0.1	0.8	1
B. Pipeline Installation[7]				
Tugboats[8]	L	26	208	312
Lay Barge	L	7	56	96
Jet Barge	L	24	192	288
Supply Boat[9]				
At Installation Site	S	2	1	2
In Transit	L	2	11	16
In Port	S	--	1	2
Crew Boat[10]				
At Installation Site	S	0.5	0.4	0.6
In Transit	L	0.5	3	5
In Port	S	--	0.4	0.6

1. All values given are based upon the level of activity required in 1985 for estimated peak construction activities.
2. The type of emission source refers to stationary (S), line (L), or area (A) sources.
3. One platform was assumed to be installed.
4. It was assumed that there would be 4 tugboats/platform installed. On an hourly basis, two were assumed to be stationary and two were assumed to be maneuvering in the general vicinity of the platform. On an annual basis, all four tugboats were assumed to be maneuvering near the platform.
5. It was assumed that there would be one supply boat per platform installed. In the maximum hour case, it was assumed that the supply boat would be at the platform for one-half an hour and in transit for one-half an hour. On an annual basis, it was assumed that 90 percent of pollutants from the supply boat would be emitted while the source is mobile (line source) between the zone and Eureka. Approximately 10 percent of the pollutants were assumed to be emitted while the source is stationary at the platform.
6. It was assumed that there would be one crew boat per platform installed. In the maximum case, the crew boat was assumed to be at the platform for one-half an hour and in transit for one-half an hour. On an annual basis, approximately 80 percent of pollutants from the crew boat would be emitted while the source is mobile (line source) between the zone and Eureka. Approximately 10 percent of the pollutants were assumed to be emitted as a stationary source at the platforms or in port.

Table C-5 (continued)

7. It was assumed that there would be 13 miles of pipeline laid in a straight route to shore.
8. It was assumed that there would be one lay barge assisted by two tugboats and one jet barge, also assisted by two tugboats. The two barges would operate about two miles apart and would progress with the pipeline installation at the rate of one mile per day.
9. It was assumed that there would be one supply boat supporting pipeline installation. In the maximum hour case, it was assumed that the supply boat would be at a barge for one-half an hour and in transit for one-half an hour. On an annual basis, it was assumed that 90 percent of pollutants from the supply boat would be emitted while the source is mobile (line source) between the zone and Eureka. Approximately 10 percent of the pollutants were assumed to be emitted while the source is stationary at the installation site.
10. It was assumed that there would be one crew boat supporting pipeline installation. In the maximum hour case, the crew boat was assumed to be at a barge for one-half an hour and in transit for one-half an hour. On an annual basis, approximately 80 percent of pollutants from the crew boat would be emitted while the source is mobile (line source) between the zone and Eureka. Approximately 10 percent of the pollutants were assumed to be emitted as a stationary source at the platforms or in port.

Table C-6. MAXIMUM HOURLY REACTIVE POLLUTANT EMISSIONS - POINT AREMA ZONE

Source/Activity[1]	Type[2]	Scenario 1		Scenario 1A		Scenario 2		Scenario 3	
		HC	NO_x	HC	NO_x	HC	NO_x	HC	NO_x
A. Production Platform[3]	S								
Development Drilling		0.5	7	0.5	7	0.5	7	0.5	7
Power Generation		8	23	8	18	8	23	8	23
Evaporative Losses		15	--	15	--	15	--	15	--
B. Offshore Storage & Treatment (OS&T)[4]	S								
Power Generation		2	16	2	11	2	16	2	16
Oil Processing		--	3	--	3	--	3	--	--
Gas Processing		415	--	--	--	415	--	415	--
Evaporative Losses		35	--	35	--	35	--	35	--
C. Floating Production Systems[5]	S								
Subsea Well Drilling		0.3	3	0.3	3	0.3	3	0.3	3
Power Generation		2	23	2	18	2	23	2	23
Evaporative Losses		15	--	15	--	15	--	15	--
D. Supportive Activities									
Supply Boats[6]	S	5	220	5	220	5	220	5	220
	L	5	220	5	220	5	220	5	220
Crew Boats[7]	S	0.5	17	0.5	17	0.5	17	0.5	17
	L	0.5	17	0.5	17	0.5	17	0.5	17
E. Transportation	S								
Tanker Loading[8]		815	2	815	2	815	2	799	10
F. Onshore Gas Processing Plant[9]	S	--	--	415	20	--	--	--	--

Table C-6 (continued)

1. Emissions correspond to the year of maximum production, which would occur in 1989.

2. The type of emission source refers to stationary (S), line (L), or area (A) sources.

3. It was assumed that there was one production platform operating.

4. In Scenario 1, 2 and 3, it was assumed that there would be one offshore storage and treatment facility (OS&T). In Scenario 1A, there would be none due to the addition of the onshore gas/oil processing plant.

5. It was assumed that there would be two floating production systems in operation. Emissions are on a "per platform" basis.

6. On a maximum hour basis, it was assumed that three supply boats would be at the platforms for one-half an hour and in transit toward San Francisco one-half an hour. Emissions for all three boats are given.

7. On a maximum hour basis, it was assumed that two crew boats would be at the platform one-half an hour and in transit toward Mendocino for one-half an hour. Emissions for both boats are given.

8. Emissions would be due to loading at tanker at the platform for one hour.

9. For Scenario 1A, the gas/oil processing plant would be located about two miles inland near Manchester.

Table C-7. MAXIMUM NITROGEN OXIDES EMISSIONS - POINT ARENA ZONE[1]

Source/Activity	Type[2]	Scenario 1		Scenario 1A		Scenario 2		Scenario 3	
		lbs/hr	tons/yr	lbs/hr	tons/yr	lbs/hr	tons/yr	lbs/hr	tons/yr
A. Production Platform[3]	S								
Development Drilling		7	3	7	3	7	3	7	3
Power Generation		23	102	18	79	23	102	23	102
B. Offshore Storage and Treatment (OS&T)[4]	S								
Power Generation		16	71	11	50	16	71	16	71
Oil Processing		3	12	3	12	3	12	3	12
C. Floating Production System[5]	S								
Subsea Drilling		3	5	3	5	3	5	3	5
Power Generation		23	102	18	79	23	102	23	102
D. Support Activities									
Supply Boats[6]									
At OS&T	S	220	8	220	8	220	8	220	8
In Transit	L	220	76	220	76	220	76	220	76
Crew Boats[7]									
At OS&T	S	17	1	17	1	17	1	17	1
In Transit	L	17	9	17	9	17	9	17	9
In Port	S	--	1	--	1	--	1	--	1
E. Tankers									
Sea Passage[8]	L	38	61	38	61	38	61	59	3
At OS&T[9]	A	--	2	--	21	--	2	--	2
	S	--	3	--	3	--	3	--	6
In Harbor[10]	L	--	11	--	11	--	11	--	--
In Port[10]	S	--	4	--	4	--	4	--	4
F. Onshore Gas Processing Plants[11]	S	--	--	20	87	--	--	--	--

Table C-7 (continued)

1. Emissions correspond to the year of maximum production, which would occur in 1989.

2. The type of emission source refers to stationary (S), line (L), or area (A) sources.

3. It was assumed that there was one production platform operating.

4. In Scenario 1, 2 and 3, it was assumed that there would be one offshore storage and treatment facility (OS&T). In Scenario 1A, there would be none due to the addition of the onshore gas/oil processing plant.

5. It was assumed that there would be two floating production systems in operation. Emissions are on a "per unit" basis.

6. On a maximum hour basis, it was assumed that three supply boats would be at the platforms for one-half an hour and in transit toward San Francisco one-half an hour. Emissions for all three boats are given. On an annual basis, it was assumed that 90 percent of pollutants from supply boats would be emitted while the sources are mobile (line source) between the zone and San Francisco. Approximately 10 percent of the pollutants were assumed to be emitted while the sources are stationary; emissions would be distributed equally among the platforms.

7. On a maximum hour basis, it was assumed that two crew boats would be at the platform one-half an hour and in transit toward Mendocino for one-half an hour. Emissions for both boats are given. On an annual basis, crew boats were assumed to be line sources from zone to shore with 10 percent of total emissions occurring at each end of the route.

8. In Scenarios 1 and 2, values are between the platform and San Francisco at 15 knots. For the 24-hour average for Scenarios 1 and 2, the time at sea would be 5.25 hours. For Scenario 3 for the annual average, transit emissions would occur for 36 nautical miles within Mendocino County in a southerly direction from the zone.

9. Values include hoteling, pumping ballast and loading activities at the platform as stationary sources, and the values for area sources represent the 3-hour time period when a ship would be maneuvering about the platform before and after loading.

10. "In harbor" emissions would occur in the San Francisco Harbor as the ship moves at a reduced speed of 6 knots landward from the Golden Gate Bridge until at docks. "In port" emissions would occur while the ship is docked.

11. For Scenario 1A, the gas/oil processing plant would be located about two miles inland near Manchester.

Table C-8. MAXIMUM SULFUR OXIDE EMISSIONS - POINT ARENA ZONE

Source/Activity	Type[2]	Scenario 1 lbs/hr	Scenario 1 lbs/3 hrs	Scenario 1 lbs/day	Scenario 1 t/yr	Scenario 1A lbs/hr	Scenario 1A lbs/3 hrs	Scenario 1A lbs/day	Scenario 1A t/yr	Scenario 2 lbs/hr	Scenario 2 lbs/3 hrs	Scenario 2 lbs/day	Scenario 2 t/yr	Scenario 3 lbs/hr	Scenario 3 lbs/3 hrs	Scenario 3 lbs/day	Scenario 3 t/yr
A. Production Platform[3]	S																
Development Drilling		3	9	78	2	3	9	78	3	3	9	78	2	3	9	78	2
Power Generation		16	48	379	69	16	48	379	69	16	48	379	69	16	48	379	69
B. Offshore Storage Treatment (OS&T)[4]	S																
Power Generation		9	27	211	38	9	27	211	38	9	27	211	38	9	27	211	38
Gas Processing		21	63	502	92	--	--	--	--	21	63	502	92	21	63	502	92
C. Floating Production System[5]	S																
Subsea Well Drilling		3	9	78	6	3	9	78	6	3	9	78	6	3	9	78	6
Power Generation		13	39	303	55	13	39	303	55	13	39	303	55	13	39	303	55
D. Supportive Activities																	
Supply Boats[6]																	
At Platform	S	15	9	68	6	15	9	68	6	15	9	68	6	15	9	68	6
In Transit	L	15	76	612	51	15	76	612	51	15	76	612	51	15	76	612	51
Crew Boats[7]																	
At Platform	S	1	0.1	0.9	0.1	1	0.1	0.9	0.1	1	0.1	0.9	0.1	1	0.1	0.9	0.1
In Transit	L	1	0.9	8	0.6	1	0.9	8	0.6	1	0.9	8	0.6	1	0.9	8	0.6
E. Tankers																	
Sea Passage[8]	L	244	732	1,281	232	244	732	1,281	232	244	732	1,281	232	376	1,129	--	18
At OS&T[9]	A	--	--	330	16	--	--	330	16	--	--	330	16	--	--	--	13
	S	--	--	540	26	--	--	540	26	--	--	540	26	--	--	1,508	30
In Harbor[10]	L	--	--	--	26	--	--	--	26	--	--	--	26	--	--	--	--
In Port[10]	S	--	--	--	6	--	--	--	6	--	--	--	6	--	--	--	--
F. Onshore Gas Processing Plant[11]	S	--	--	--	--	21	63	502	92	--	--	--	--	--	--	--	--

Table C-8 (continued)

1. Emissions correspond to the year of maximum production, which would occur in 1989.

2. The type of emission source refers to stationary (S), line (L), or area (A) sources.

3. It was assumed that there was one production platform operating.

4. In Scenario 1, 2 and 3, it was assumed that there would be one offshore storage and treatment facility (OS&T). In Scenario 1A, there would be none due to the addition of the onshore gas/oil processing plant.

5. It was assumed that there would be two floating production systems in operation. Emissions are on a "per unit" basis.

6. On a maximum hour basis, it was assumed that three supply boats would be at the platforms for one-half an hour and in transit toward San Francisco one-half an hour. Emissions for all three boats are given. On an annual basis, it was assumed that 90 percent of pollutants from supply boats would be emitted while the sources are mobile (line source) between the zone and San Francisco. Approximately 10 percent of the pollutants were assumed to be emitted while the sources are stationary; emissions would be distributed equally among the platforms.

7. On a maximum hour basis, it was assumed that two crew boats would be at the platform one-half an hour and in transit toward Mendocino for one-half an hour. Emissions for both boats are given. On an annual basis, crew boats were assumed to be line sources from zone to shore with 10 percent of total emissions occurring at each end of the route.

8. In Scenarios 1 and 2, values are between the platform and San Francisco at 15 knots. For the 24-hour average for Scenarios 1 and 2, the time at sea would be 5.25 hours. For Scenario 3 for the annual average, transit emissions would occur for 36 nautical miles within Mendocino County in a southerly direction from the zone.

9. Values include hoteling, pumping ballast and loading activities at the platform as stationary sources, and the values for area sources represent the 3-hour time period when a ship would be maneuvering about the platform before and after loading.

10. "In harbor" emissions would occur in the San Francisco Harbor as the ship moves at a reduced speed of 6 knots landward from the Golden Gate Bridge until at docks. "In port" emissions would occur while the ship is docked.

11. For Scenario 1A, the gas/oil processing plant would be located about two miles inland near Manchester.

Table C-9. MAXIMUM TOTAL SUSPENDED PARTICULATE EMISSIONS - POINT ARENA ZONE

Source/Activity[1]	Type[2]	Scenario 1		Scenario 1A		Scenario 2		Scenario 3	
		lbs/day	tons/yr	lbs/day	tons/yr	lbs/day	tons/yr	lbs/day	tons/yr
A. Production Platform[3]	S								
Development Drilling		10	0.2	10	0.2	10	0.2	10	0.2
Power Generation		53	10	53	10	53	10	53	10
B. Offshore Storage and Treatment (OS&T)[4]	S								
Power Generation		38	7	--	--	38	7	38	7
Oil Processing		7	1	--	--	7	1	7	1
C. Floating Production System[5]	S								
Subsea Drilling		5	0.7	5	0.7	5	0.7	5	0.7
Power Generation		53	10	53	10	53	10	53	10
D. Support Activities									
Supply Boats[6]									
At Platforms	S	44	4	44	4	44	4	44	4
In Transit	L	393	33	393	33	393	33	393	33
Crew Boats[7]									
At Platforms	S	0.6	Neg.	0.6	Neg.	0.6	Neg.	0.6	Neg.
In Transit	L	5	0.4	5	0.4	5	0.4	5	0.4
E. Tankers									
Sea Passage[8]	L	25	1	25	1	25	1	--	1
At OS&T[9]	A	30	1	30	1	30	1	--	0.8
	S	32	2	32	2	32	2	90	2
In Harbor[10]	A	--	2	--	2	--	2	--	--
In Port[10]	S	--	1	--	1	--	1	--	--
F. Onshore Gas Processing Plant[11]	S	--	--	45	8	--	--	--	--

Table C-9 (continued)

1. Emissions correspond to the year of maximum production, which would occur in 1989.

2. The type of emission source refers to stationary (S), line (L), or area (A) sources.

3. It was assumed that there was one production platform operating.

4. In Scenario 1, 2 and 3, it was assumed that there would be one offshore storage and treatment facility (OS&T). In Scenario 1A, there would be none due to the addition of the onshore gas/oil processing plant.

5. It was assumed that there would be two floating production systems in operation. Emissions are on a "per unit" basis.

6. On a maximum hour basis, it was assumed that three supply boats would be at the platforms for one-half an hour and in transit toward San Francisco one-half an hour. Emissions for all three boats are given. On an annual basis, it was assumed that 90 percent of pollutants from supply boats would be emitted while the sources are mobile (line source) between the zone and San Francisco. Approximately 10 percent of the pollutants were assumed to be emitted while the sources are stationary; emissions would be distributed equally among the platforms.

7. On a maximum hour basis, it was assumed that two crew boats would be at the platform one-half an hour and in transit toward Mendocino for one-half an hour. Emissions for both boats are given. On an annual basis, crew boats were assumed to be line sources from zone to shore with 10 percent of total emissions occurring at each end of the route.

8. In Scenarios 1 and 2, values are between the platform and San Francisco at 15 knots. For the 24-hour average for Scenarios 1 and 2, the time at sea would be 5.25 hours. For Scenario 3 for the annual average, transit emissions would occur for 36 nautical miles within Mendocino County in a southerly direction from the zone.

9. Values include hoteling, pumping ballast and loading activities at the platform as stationary sources, and the values for area sources represent the 3-hour time period when a ship would be maneuvering about the platform before and after loading.

10. "In harbor" emissions would occur in the San Francisco Harbor as the ship moves at a reduced speed of 6 knots landward from the Golden Gate Bridge until at docks. "In port" emissions would occur while the ship is docked.

11. For Scenario 1A, the gas/oil processing plant would be located about two miles inland near Manchester.

Table C-10. MAXIMUM CARBON MONOXIDE EMISSIONS - POINT ARENA ZONE

Source/Activity[1]	Type[2]	Scenario 1			Scenario 1A			Scenario 2			Scenario 3		
		lbs/hr	lbs/8 hrs	lbs/12 hrs	lbs/hr	lbs/8 hrs	lbs/12 hrs	lbs/hr	lbs/8 hrs	lbs/12 hrs	lbs/hr	lbs/8 hrs	lbs/12 hrs
A. Production Platform[3]													
Development Drilling	S	1	10	16	1	10	16	1	10	16	1	10	16
Power Generation		5	39	59	5	39	59	5	39	59	5	39	59
B. Offshore Storage and Treatment(OS&T)[4]	S												
Power Generation		4	29	43	--	--	--	4	29	43	4	29	43
Oil Processing		0.5	4	7	--	--	--	0.5	4	7	0.5	4	7
C. Floating Production Systems[5]	S												
Subsea Well Drilling		0.7	6	8	0.7	6	8	0.7	6	8	0.7	6	8
Power Generation		5	39	59	5	39	59	5	39	58	5	39	58
D. Supportive Activities													
Supply Boats[6]													
At Platform	S	33	53	80	33	53	80	33	53	80	33	53	80
In Transit	L	33	477	716	33	477	716	33	477	716	33	477	716
Crew Boats[7]													
At Platform	S	3	0.9	1	3	0.9	1	3	0.9	1	3	0.9	1
In Transit	L	3	8	12	3	8	12	3	8	12	3	8	12
E. Tankers													
Sea Passage[8]	L	0.5	--	--	0.5	--	--	0.5	--	--	0.7	--	--
At OS&T[9]	A	--	1	1	--	1	1	--	1	1	--	2	1
	S	--	0.4	0.6	--	0.4	0.6	--	0.4	0.8	--	0.4	0.8
F. Onshore Gas Processing Plant[10]	S	--	--	--	5	33	50	--	--	--	--	--	--

Table C-10 (continued).

1. Emissions correspond to the year of maximum production, which would occur in 1989.

2. The type of emission source refers to stationary (S), line (L), or area (A) sources.

3. It was assumed that there was one production platform operating.

4. In Scenario 1, 2 and 3, it was assumed that there would be one offshore storage and treatment facility (OS&T). In Scenario 1A, there would be none due to the addition of the onshore gas/oil processing plant.

5. It was assumed that there would be two floating production systems in operation. Emissions are on a "per unit" basis.

6. On a maximum hour basis, it was assumed that three supply boats would be at the platforms for one-half an hour and in transit toward San Francisco one-half an hour. Emissions for all three boats are given. On an annual basis, it was assumed that 90 percent of pollutants from supply boats would be emitted while the sources are mobile (line source) between the zone and San Francisco. Approximately 10 percent of the pollutants were assumed to be emitted while the sources are stationary; emissions would be distributed equally among the platforms.

7. On a maximum hour basis, it was assumed that two crew boats would be at the platform one-half an hour and in transit toward Mendocino for one-half an hour. Emissions for both boats are given. On an annual basis, crew boats were assumed to be line sources from the zone to shore with 10 percent of total emissions occurring at each end of the route as stationary sources.

8. For Scenarios 1 and 2, values are for sea passage between the platform and San Francisco at 15 knots. For Scenario 3, sea passage emissions would occur in a southerly direction from the zone at a speed of 16 knots.

9. Values include pumping ballast and loading at the platform as stationary sources. Area source emissions include maneuvering near the OS&T.

10. For Scenario 1A, the gas/oil processing plant would be located about two miles inland near Manchester.

Table C-11. MAXIMUM HOURLY REACTIVE POLLUTANT EMISSIONS - BODEGA ZONE[1]

Source/Activity	Type[2]	Scenario 1		Scenario 1A		Scenario 2		Scenario 3	
		HC	NO_x	HC	NO_x	HC	NO_x	HC	NO_x
A. Production Platform[3]	S								
Development Drilling		0.5	6	0.5	6	0.5	6	0.5	6
Power Generation		1	12	1	12	1	12	1	12
Evaporative Losses		5	--	5	--	5	--	5	--
B. Offshore Storage & Treatment (OS&T)[4]	S								
Power Generation		0.2	2	0.2	2	0.2	2	0.2	2
Oil Processing		--	0.5	--	0.5	--	0.5	--	0.5
Evaporative Losses		9	--	9	--	9	--	9	--
C. Supportive Activities									
Supply Boat[5]									
At Platform	S	1	42	1	42	1	42	1	42
In Transit	L	2	84	2	84	2	84	2	84
Crew Boats[6]									
At Platform	S	0.15	0.5	0.15	0.5	0.15	0.5	0.15	0.5
In Transit	L	0.15	0.5	0.15	0.5	0.15	0.5	0.15	0.5
D. Tankers[7]									
At OS&T	S	609	17	609	17	609	17	799	8

1. The maximum hour emissions for oxidants was assumed to occur in 1987, the expected peak production year.
2. The type of emission source refers to stationary (S), area (A), or line (L) sources.
3. It was assumed that there would be one platform in this zone. Two wells were assumed to be drilled on the platform in a maximum hour scenario.
4. It was assumed that one offshore storage and treatment facility (OS&T) would be needed in this zone. Oil would be partially processed and stored in the OS&T. Barges will also be loaded at the OS&T.
5. Assumes two supply boats for this zone. One supply boat was assumed to be in transit during the maximum hour scenario at 13 knots. The other supply boat was assumed to be at the platform for one-half an hour and in transit for one-half an hour. Supply boats would shuttle between the platforms and the San Francisco Bay Area.
6. Assumes one crew boat which would remain as a stationary source at the platform or OS&T for one half an hour and in transit toward the shore for one-half an hour at 17 knots.
7. The maximum hour emission scenario assumes a 15,000 barrel barge loading at the OS&T for Transportation Scenarios 1, 1A, and 2. For Transportation Scenario 3, maximum hourly emissions were assumed to occur during the loading of a 25,000 deadweight ton(DWT) tanker at the OS&T.

Table C-12. MAXIMUM NITROGEN OXIOE EMISSIONS - BODEGA ZONE[1]

Source/Activity	Type[2]	Scenario 1		Scenario 1A		Scenario 2		Scenario 3	
		lbs/hr	tons/yr	lbs/hr	tons/yr	lbs/hr	tons/yr	lbs/hr	tons/yr
Platform Installation[3]									
Derrick Barge	S	69	180	69	180	69	180	69	180
Tugboats[4]	S	86	--	86	--	86	--	86	--
Tugboats	A	86	451	86	451	86	451	86	451
Supply Boats[5]									
In Transit	L	35	83	35	83	35	83	35	83
At Platform	S	35	9	35	9	35	9	35	9
Crew Boats[6]									
In Transit	L	6	4	6	4	6	4	6	4
At Platform	S	5	0.5	5	0.5	5	0.5	5	0.5
In Port	S	--	0.5	--	0.5	--	0.5	--	0.5

1. Nitrogen oxide emissions in this zone were assumed to be at the highest level in 1985.
2. The type of emission source refers to stationary (S), line (L), or area (A) sources.
3. One platform was assumed to be installed.
4. It was assumed that there would be 4 tugboats/platform installed. On an hourly basis, two tugboats were assumed to be stationary and two were assumed to be maneuvering in the general vicinity of the platform. On an annual basis, all four tugboats were assumed to be maneuvering near the platforms.
5. It was assumed that there would be one supply boat per platform installed. In the maximum hour case, it was assumed that the supply boat would be at platform for one-half an hour and in transit for one half an hour. On an annual basis it was assumed that 90 percent of the pollutants from the supply boat would be emitted while the sources are mobile (line sources) between the zone and San Francisco. Approximately 10 percent of the pollutants were assumed to be emitted while the source is stationary at the platform.

Table C-12 (continued)

6. It was assumed that there would be one crew boat per platform installed. In the maximum hour case, the crew boat was assumed to be at the platform for one-half an hour and in transit for one-half an hour. On an annual basis, the crew boat was assumed to be a line source extending from the zone to the nearest port with 10 percent of the total emissions occurring at each end of the route as a stationary source.

Table C-13. MAXIMUM SULFUR OXIDE EMISSIONS - BODEGA ZONE[1]

Source/Activity	Type[2]	Scenario 1				Scenario 1A				Scenario 2				Scenario 3			
		lbs/hr	lbs/3 hrs	lbs/day	t/yr	lbs/yr	lbs/3 hrs	lbs/day	t/yr	lbs/hr	lbs/3 hrs	lbs/day	t/yr	lbs/hr	lbs/3 hrs	lbs/day	t/yr
A. Production Platform (with drilling)[3]	S																
Development Drilling		3	9	72	3	3	9	72	3	3	9	72	3	3	9	72	3
Power Generation		7	20	161	29	7	20	161	29	7	20	161	29	7	20	161	29
B. Offshore Storage and Treatment Facility (OS&T)[3]	S																
Power Generation		1	3	24	4	1	3	24	4	1	3	24	4	1	3	24	4
C. Support Activity Supply Boats[4]																	
In Transit	L	7	23	78	9	7	23	78	9	7	23	78	9	7	23	78	9
At Platforms	S	2	3	9	1	2	3	9	1	2	3	9	1	2	3	9	1
D. Crew Boats[5]																	
In Transit	L	0.8	1	5	0.5	0.8	1	5	0.5	0.8	1	5	0.5	0.8	1	5	0.8
At Platforms	S	0.1	0.2	1	0.1	0.1	0.2	1	0.1	0.1	0.2	1	0.1	0.1	0.2	1	0.1
In Port	S	0.1	0.2	1	0.1	0.1	0.2	1	0.1	0.1	0.2	1	0.1	0.1	0.2	1	0.1
E. Tankers[6]																	
Sea Passage[6]	L	--	--	9	0.4	--	--	9	0.4	--	--	9	0.4	--	--	1,122	10
At OS&T[7]	A	--	--	4	0.2	--	--	4	0.2	--	--	4	0.2	--	--	329	3
	S	1	4	6	0.3	1	4	6	0.3	1	4	6	0.3	50	150	777	0.5
In Port[8]	S	--	--	4	0.7	--	--	4	0.7	--	--	4	0.7	--	--	--	--
In Harbor[9]	L	--	--	6	0.3	--	--	6	0.3	--	--	6	0.3	--	--	--	--

Table C-13 (continued)

1. Sulfur oxide emissions were assumed to be at the highest level in this zone in 1987.
2. The type of source refers to stationary (S), line (L), or area (A) sources.
3. Assumes one platform in the zone in addition to one OS&T.
4. For the maximum one hour emission scenario, it is assumed that two supply boats are in operation. One supply boat is assumed to be a mobile source traveling from the platform to the San Francisco area at 13 knots. The remaining 10 percent was assumed to be emitted from the supply boats while at the platform (a stationary source).
5. For the maximum one hour emission scenario, the crew boat was assumed to be a stationary source for one-half an hour while waiting at the platform and a mobile source for the other one-half an hour (traveling to the nearest port at 17 knots). For other averaging periods 80 percent of the pollutants were assumed to be emitted while the crew boat travels from the platform to the nearest point (a line source). The remaining 20 percent of pollutants were assumed to be emitted by the boat while it is stationary, docking at the platform or at the port (10 percent each).
6. Mobile source daily emissions for Scenarios 1,1A and 2 would include tanker sea passage emissions while the tanker travels from San Francisco area to the Bodega Zone. In Scenario 3, daily mobile emissions are based on an assumed 2.5 hours of tanker sea passage towards the OS&T from a southerly direction 35 nautical miles away, and 2.5 hours of sea passage away from the OS&T 36 nautical miles to the south. Annual mobile emissions are based on barges which would be towed between the Bodega Zone and the San Francisco area in Transportation Scenarios 1, 1A and 2. For Transportation Scenario 3, tanker sea passage emissions for round trip in a stretch extending 36 nautical miles to the south of the OS&T system are assumed for annual emissions per round trip. This portion of the tanker route was assumed to be within the extended onshore boundaries of Bay Area Air Quality Management District.
7. Emissions associated with barge/tanker loading activities at the OS&T are considered for one hour and three hour emission scenarios. The stationary activity would be loading, while the area sources will be ships maneuvering about the OS&T for three hours.
8. Onshore daily emissions for transportation Scenarios 1, 1A, and 2 include 7 hours of offloading and 3 hours of hoteling while the barge would be docked at San Francisco Bay Area.
9. Onshore daily emissions from line sources for Scenarios 1, 1A and 2 include five hours would travel at a reduced speed landward of the Golden Gate Bridge and docking (or undocking).

Table C-14. MAXIMUM TOTAL SUSPENDED PARTICULATE EMISSIONS - BODEGA ZONE[1]

Source/Activity	Type[2]	Scenarios 1, 1A, 2, and 3 lbs/day	tons/year
A. Platform Installation[3]			
Derrick Barge	S	100	11
Tugboat[4]	L	162	18
Tugboat[4]	S	18	2
Supply Boats[5]			
In Transit	L	28	4
At Platform	S	9	0.4
Crew Boats		Neg.	Neg.

1. Particulate matter emissions were assumed to be at the peak level in this zone in 1985.
2. The type of emission source refers to stationary (S), line (L), or area (A) sources.
3. Assumes one platform installed in 1985. Emissions associated with installation of the OS&T were assumed to be negligible.
4. Assumes four tugboats for platform installation. Two of these tugboats were assumed to be stationary most of the time with the other two tugboats maneuvering in the general vicinity of the platform being installed.
5. Assumes one supply boat for platform installation. For the averaging periods shown in the table, it was assumed that 90 percent of emissions were from mobile sources (line source) extending from the platform to the distance that can be traveled by the source during each particular averaging period. The remaining 10 percent of the emissions were assumed to be from stationary sources located at platform installation site.

Table C-15. MAXIMUM CARBON MONOXIDE EMISSIONS - BODEGA ZONE[1]

Source/Activity	Type[2]	Scenarios 1, 1A, 2, and 3 lbs/hr	lbs/8 hrs	lbs/12 hrs
A. Platform Installation[3]				
Derrick Barge	S	13	105	157
Tugboats[4]	A	13	103	63
Tugboats[4]	S	13	103	63
B. Supply Boats[5]				
In Transit	L	5	68	113
At Platform	S	4	8	13
C. Crew Boats[6]				
In Transit	L	1	2	5
At Platform	S	1	1	1
In Port	S	--	1	1

1. Carbon monoxide emissions were assumed to be at the peak level in this zone in 1985.
2. The type of emission source refers to stationary (S), line (L), or area (A) sources.
3. Assumes one platform installed in 1985. Emissions associated with installation of the OS&T were assumed to be negligible.
4. Assumes four tugboats for platform installation. Two of these tugboats were assumed to be stationary most of the time with the other two tugboats maneuvering in the general vicinity of the platform being installed.
5. Assumes one supply boat for platform installation. For the maximum hour scenario, it was assumed that the supply boat stays at the platform for one-half an hour as a stationary source, and would be in-transit at 13 knots for one-half an hour. For other averaging periods it was assumed that 90 percent of emissions were from mobile sources (line source) extending from the platform to the distance that can be traveled by the source during particular averaging period. The remaining 10 percent of the emissions were assumed to be from stationary sources located at platform installation site.
6. Assumes one crew boat for this zone in 1985. For the maximum hour scenario, the crew boat was assumed to stay one-half an hour at the platform as a stationary source, and to be in-transit for one-half an hour at 17 knots. For other averaging periods, it was assumed that 80 percent of the emissions occur while the source is traveling from the zone to port (line source) with 10 percent of the emissions occurring in port as a stationary source. The remaining 10 percent of pollutants were assumed to be emitted from the boat and may be considered as stationary sources anchoring at the platform installation site.

Table C-16. MAXIMUM HOURLY REACTIVE POLLUTANT EMISSIONS - SANTA CRUZ ZONE[1]
(lbs/hr)

Source/Activity	Type[2]	Scenario 1		Scenario 1A		Scenario 2		Scenario 3	
		HC	NO_x	HC	NO_x	HC	NO_x	HC	NO_x
A. Production Platform (with drilling)[3]	S								
Development Drilling		0.5	6	0.5	6	0.5	6	0.5	6
Power Generation		1	10	1	13	1	10	1	10
Evaporative Losses		8	--	9	--	8	--	8	--
B. Production Platform (without drilling)[4]	S								
Power Generation		1	10	1	10	1	10	1	10
Evaporative Losses		8	--	3	--	8	--	8	--
C. Floating Production System[5]									
Power Generation		1	10	3	19	1	10	1	10
Evaporative Losses		18	--	24	--	18	--	18	--
D. Offshore Storage & Treatment (OS&T)[6]	S								
Power Generation		3	24	--	--	2	14	2	14
Oil and Gas Processing		312	2	--	--	312	2	312	2
Evaporative Losses		24	--	--	--	23	--	23	--
E. Onshore Gas Processing Plant[7]	S								
Oil Processing		--	--	0.2	2	--	--	--	--
Gas Processing		--	--	312	--	--	--	--	--
Gas Compression		--	--	--	15	--	--	--	--
F. Pipeline (from OS&T to shore)	L	17	--	17	--	9	--	9	--
G. Supportive Activity									
Supply Boats[8]									
In Transit	L	2	95	2	95	2	95	2	95
At Platform	S	2	94	2	94	2	94	2	94
Crew Boats[9]									
In Transit	L	0.5	17	0.5	17	0.5	17	0.5	17
At Platform	S	0.5	17	0.5	17	0.5	17	0.5	17
In Port	S	--	--	--	--	--	--	--	--
H. Tankers									
At OS&T[10]	S	--	--	--	--	1,741	43	799	10

Table C-16 (continued)

1. Hourly reactive pollutant emissions were estimated to be at the highest level in 1990.
2. The type of emission source refers to stationary (S), line (L), or area (A) sources.
3. It was assumed that there would be two platforms drilling simultaneously. Emissions are on a "per platform" basis.
4. It was assumed that there would be two production platforms. Emissions are on a "per platform" basis.
5. It was assumed that there would be one floating production system in this year.
6. In Scenarios 1, 2 and 3, it was assumed that there would be two offshore storage and treatment (OS&T) facilities. In Scenario 1A, there would be none due to the addition of the onshore oil/gas processing plant.
7. For Scenario 1A, the oil/gas processing plant would be located approximately two miles inland.
8. On a maximum hour basis, it was assumed that three supply boats would be at platforms for one-half an hour and in transit back to the point of origin (San Francisco) for one-half an hour. Emissions for all three boats are given. On an annual basis, it was assumed that 90 percent of polutants from supply boats would be emitted while the sources are mobile (line sources) between the zone and San Francisco. Approximately 10 percent of the pollutants were assumed to be emitted while the sources are stationary; emissions would be distributed equally among the platforms.
9. On a maximum hour basis, it was assumed that three crew boats would be at the platforms for one-half an hour and in transit back to the point of origin (nearest port) for one-half an hour. Emissions for all three boats are given. On an annual basis, crew boats were assumed to be line sources from the zone to shore with 10 percent of total emissions occurring at each end of the route.
10. Emissions would be due to the loading of one tanker at the OS&T for one hour

Table C-17. MAXIMUM NITROGEN OXIDE EMISSIONS - SANTA CRUZ ZONE[1]

Source/Activity	Type[2]	Scenario 1		Scenario 1A		Scenario 2		Scenario 3	
		lbs/hr	tons/yr	lbs/hr	tons/yr	lbs/hr	tons/yr	lbs/hr	tons/yr
A. Platform Installation[3]									
Derrick Barge	S	69	300	69	300	69	300	69	300
Tugboats[4]	S	86	--	86	--	86	--	86	--
Tugboats[4]	A	86	451	86	451	86	451	86	451
Supply Boats[5]									
In Transit	L	32	67	32	67	32	67	32	67
At Platform	S	31	7	31	7	31	7	31	7
Crew Boats[6]									
In Transit	L	6	4	6	4	6	4	6	4
At Platform	S	5	0.5	5	0.5	5	0.5	5	0.5
In Port	S	--	0.5	--	0.5	--	0.5	--	0.5
B. Production Platform (with drilling)[7]									
Development Drilling	S	16	14	16	14	16	14	16	14
Power Generation	S	7	32	7	32	7	32	7	32
C. Production Platform (without drilling)[8]									
Power Generation	S	7	32	7	32	7	32	7	32
D. Floating Production System[9]									
Development Drilling	S	6	3	6	3	6	3	6	3
Power Generation	S	7	32	14	61	7	32	7	32
E. Offshore Storage & Treatment (OS&T)[10]									
Power Generation	S	14	64	--	--	8	36	8	36
Oil Processing	S	1	5	--	--	1	5	1	5
F. Onshore Gas Processing Plant[11]									
Oil Processing	S	--	--	1	5	--	--	--	--
Gas Processing (Power Generation)	S	--	--	9	38	--	--	--	--

Table C-17 (continued)

Source/Activity	Type[2]	Scenario 1		Scenario 1A		Scenario 2		Scenario 3	
		lbs/hr	tons/yr	lbs/hr	tons/yr	lbs/hr	tons/yr	lbs/hr	tons/yr
G. Supportive Activity									
Supply Boats[12]									
In Transit	L	126	235	126	235	126	235	126	235
At Platforms	S	126	29	126	29	126	29	126	29
Crew Boats[13]									
In Transit	L	23	22	23	22	23	22	23	22
At Platform	S	22	3	22	3	22	3	22	3
In Port	S	--	3	--	3	--	3	--	3
I. Tankers									
Sea Passage[14]	L	--	--	--	--	--	9	--	13
At OS&T[16]									
Maneuvering	A	--	--	--	--	--	5	--	3
Stationary	S	--	--	--	--	43	14	10	3
In Harbor[16]	L	--	--	--	--	--	8	--	--
In Port[17]	A	--	--	--	--	--	24	--	--

1. Nitrogen oxide emissions are estimated to be at the highest level in this zone in 1988.
2. The type of emission source refers to stationary (S), line (L), or area (A) sources.
3. One platform was assumed to be installed.
4. It was assumed that there would be four tugboats/platform installed. On an hourly basis, two were assumed to be stationary and two were assumed to be maneuvering in the general vicinity of the platform. On an annual basis, all four tugboats were assumed to be maneuvering near the platforms; stationary annual emissions were not considered significant.
5. It was assumed that there would be one supply boat per platform installed. In the maximum hour case, it was assumed that the supply boat would be at platform for one-half an hour and in transit for one half an hour. On an annual basis, it was assumed that 90 percent of pollutants would be emitted while the supply boat is mobile (line source) between San Francisco and the Santa Cruz zone. The remaining 10 percent of the pollutants were assumed to be emitted while the source is stationary at the platform. Emissions would be distributed equally among the platforms being installed.
6. It was assumed that there would be one crew boat per platform installed. In the maximum hour case, the crew boa was assumed to be at the platform for one-half an hour and in transit for one-half an hour. On an annual basis, 80 percent of the crew boat emissions were assumed to be a line source extending from the zone to the nearest port with 10 percent of the total emissions occurring at each end of the route (at platform and in port) while the boats are assumed to act as a stationary source.

Table C-17 (continued)

7. It was assumed that there would be two platforms drilling simultaneously. Emissions are on a "per platform" basis.
8. It was assumed that there would be three production platforms. Emissions are on a "per platform" basis.
9. It was assumed that there would be one floating production system in this year.
10. In Scenarios 1, 2 and 3, it was assumed that there would be one offshore storage and treatment (OS&T) facility. In Scenario 1A, there would be none due to the addition of the onshore oil/gas processing plant.
11. For Scenario 1A, the oil/gas processing plant would be located about 2 miles inland.
12. On a maximum hour basis, it was assumed that four supply boats would be at platforms for one-half an hour and in transit back to the origin (San Francisco) for one-half an hour. Emissions for all four boats are given. On an annual basis, it was assumed that 90 percent of pollutants from the boats would be emitted while the sources are mobile (line sources) traveling between San Francisco and the Santa Cruz zone. Approximately 10 percent of the pollutants were assumed to be emitted while the sources are stationary, emissions would be distributed among the platforms.
13. On a maximum hour basis, it was assumed that three crew boats would be at the platforms for one-half an hour and in transit back to the origin (nearest port) for one-half an hour. Emissions for all three boats are given. On an annual basis, 80 percent of crew boat emissions were assumed to be line sources traveling from zone to shore with 10 percent of total emissions occurring at each end of the route (at platform and in port) while the boats are considered as stationary sources.
14. Annual sea passage emissions in Scenario 2 are based on 6 hours of traveling time required for a round trip from the zone to the Golden Gate Bridge at 15 knots. In Scenario 3 the sea passage emissions are based on a round trip distance of 103 nautical miles which would be traveled by the tanker at 16 knots. This distance is assumed to be the extended boundaries of the Bay Area Air Quality Management District (BAAQMD) (on shore boundaries of BAAQMD were extended seaward).
15. Maneuvering emissions in Scenario 2 and 3 include emissions associated with 3 hours of maneuvering assumed to be required for tanker/barge arrival and departure at the OS&T. Stationary emissions associated with Scenarios 2 and 3 would be tanker loading, hoteling, and ballast discharge operations.
16. In harbor emissions are associated with tanker/barge traveling at a reduced speed within the San Francisco Bay area from the Golden Gate Bridge to the terminal.
17. In port emissions include emissions associated with offloading, hoteling, ballasting, and refueling activities.

Table C-18. MAXIMUM SULFUR OXIDE EMISSIONS - SANTA CRUZ ZONE[1]

Source/Activity	Type[2]	Scenario 1 lbs/hr	lbs/3 hrs	lbs/day	t/yr	Scenario 1A lbs/hr	lbs/3 hrs	lbs/day	t/yr	Scenario 2 lbs/hr	lbs/3 hrs	lbs/day	t/yr	Scenario 3 lbs/hr	lbs/3 hrs	lbs/day	t/yr
A. Production Platform (with drilling)[3]	S																
Development Drilling		3	7	78	11	3	7	78	11	3	7	78	11	3	7	78	11
Power Generation		6	16	131	24	7	21	166	30	6	16	131	24	6	16	131	24
B. Production Platform (without drilling)[4]	S																
Power Generation		6	16	131	24	7	21	166	30	6	16	131	24	6	16	131	24
C. Floating Production System[5]	S																
Power Generation		6	16	131	24	13	38	304	55	6	16	131	24	6	16	131	24
D. Offshore Storage and Treatment (OS&T)[6]	S																
Power Generation		13	39	311	157	--	--	--	--	13	39	311	157	13	39	311	157
Gas/Oil Processing		16	47	379	69	--	--	--	--	16	47	379	69	16	47	379	69
E. Onshore Gas Processing Plant[7]	S																
Gas Processing		--	--	--	--	16	47	379	69	--	--	--	--	--	--	--	--
F. Supportive Activity Supply Boats[8]																	
In Transit	L	6	19	149	15	6	19	149	15	6	19	149	15	6	19	149	15
At Platforms	S	6	2	17	2	6	2	17	2	6	2	17	2	6	2	17	2
Crew Boats[9]																	
In Transit	L	2	3	10	0.8	2	3	10	0.8	1	3	10	0.8	1	3	10	0.8
At Platform	S	0.2	0.4	1	0.1	0.2	0.4	1	0.1	0.2	0.4	1	0.1	0.2	0.4	1	0.1
In Port	S	0.2	0.4	1	0.1	0.2	0.4	1	0.1	0.2	0.4	1	0.1	0.2	0.4	1	0.1
G. Tankers																	
In Transit[10,11]	L	--	--	--	--	--	--	--	--	--	--	9	3	376	1,129	--	45
At OS&T[12]	A	--	--	--	--	--	--	--	--	--	--	3	0.5	--	--	--	9
	S	--	--	--	--	--	--	--	--	3	9	23	2	--	--	1,508	28
In Port[13]	S	--	--	--	--	--	--	--	--	--	--	29	3	--	--	--	--
In Harbor[13]	L	--	--	--	--	--	--	--	--	--	--	7	0.9	--	--	--	--

Table C-18 (continued)

1. Sulfur oxide emissions were estimated to be at the highest level in this zone in 1990.

2. The type of source refers to stationary (S), line (L), or area (A) sources.

3. It was assumed that there would be two platforms drilling simultaneously. Emissions are on a "per platform" basis.

4. It was assumed that there would be two production platforms. Emissions are on a "per platform" basis.

5. It was assumed that there would be one floating production system in this year.

6. In Scenarios 1, 2 and 3, it was assumed that there would be two offshore storage and treatment (OS&T) facilities. In Scenario 1A, there would be done due to the addition of the onshore oil/gas processing plant. Emissions are on a "per OS&T" basis.

7. For Scenario 1A, the oil/gas processing plant would be located approximately two miles inland.

8. On a maximum hour basis, it was assumed that three supply boats would be at platforms for one-half an hour and in transit back to the point of origin (San Francisco) for one-half an hour. Emissions for all three boats are given. On an annual basis, it was assumed that 90 percent of pollutants would be emitted while the sources are mobile (line sources) between the zone and San Francisco. Approximately 10 percent of the pollutants were assumed to be emitted while the sources are stationary; emissions would be distributed equally among the platforms.

9. On a maximum hour basis, it was assumed that three crew boats would be at the platforms for one-half an hour and in transit back to the point of origin (nearest port) for one-half an hour. Emissions for all three boats are given. On an annual basis, crew boats were assumed to be line sources from the zone to shore with 10 percent of total emissions occurring at each end of the route.

10. In Scenario 2, the daily and annual values represent sea passage from the platform to San Francisco.

11. In Scenario 3, the values represent sea passage time for either the stated period or until the ship would move south of the Santa Cruz/Monterey County line.

12. In Scenario 2, the one-hour and three-hour values represent emissions due to the loading of one tanker. The daily and annual values include hoteling and ballasting operations emissions.

13. Emissions would occur in San Francisco. The stationary emissions would include offloading, hoteling and refueling. The line source emissions would be from the ship traveling at a reduced rate from the Golden Gate Bridge and docking.

Table C-19 MAXIMUM TOTAL SUSPENDED PARTICULATE EMISSIONS - SANTA CRUZ ZONE[1]

Source/Activity	Type[2]	Scenario 1		Scenario 1A		Scenario 2		Scenario 3	
		lbs/day	tons/yr	lbs/day	tons/yr	lbs/day	tons/yr	lbs/day	tons/yr
A. Platform Installation[3]									
Derrick Barge	S	100	11	100	11	100	11	100	11
Tugboats[4]	S	72	10	72	10	72	10	72	10
Tugboats	A	72	10	72	10	72	10	72	10
Supply Boats[5]									
In Transit	L	26	3	26	3	26	3	26	3
At Platform	S	3	0.3	3	0.3	3	0.3	3	0.3
Crew Boats[6]									
In Transit	L	9	0.8	9	0.8	9	0.8	9	0.8
At Platform	S	1	0.1	1	0.1	1	0.1	1	0.1
In Port	S	1	0.1	1	0.1	1	0.1	1	0.1
B. Production Platform (with drilling)[7]	S								
Development Drilling		10	0.6	10	0.6	10	0.6	10	0.6
Power Generation		17	3	21	4	17	3	17	3
C. Production Platform (without drilling)[8]									
Power Generation	S	17	3	21	4	17	3	17	3
D. Floating Production System[9]	A								
Development Drilling		10	0.2	10	0.2	10	0.2	10	0.2
Power Generation		17	3	40	7	17	3	17	3
E. Offshore Storage & Treatment (OS&T)[10]	S								
Power Generation		19	3	--	--	19	3	19	3
Oil Processing		3	0.5	--	--	3	0.5	3	0.5
F. Onshore Gas Processing Plant[11]	S								
Oil Processing		--	--	3	0.6	--	--	--	--
Gas Processing (Power Generation)		--	--	--	--	--	--	--	--
G. Supportive Activity									
Supply Boats[12]									
In Transit	L	127	14	127	14	127	14	127	14
At Platform	A	14	2	14	2	14	2	14	2
Crew Boats[13]									
In Transit	L	9	0.8	9	0.8	9	0.8	9	0.8
At Platform	S	1	0.1	1	0.1	1	0.1	1	0.1
In Port	S	1	0.1	1	0.1	1	0.1	1	0.1

Table C-19 (continued)

Source/Activity	Type[2]	Scenario 1		Scenario 1A		Scenario 2		Scenario 3	
		lbs/day	tons/yr[3]	lbs/day	tons/yr	lbs/day	tons/yr	lbs/day	tons/yr
H. Tankers									
Sea Passage[14]	L	--	--	--	--	6	0.4	92	1
At Platform[15]	S	--	--	--	--	15	0.6	--	1
	A	--	--	--	--	2	0.2	--	0.3
In port[16]	S	--	--	--	--	19	1	--	--
In Harbor[17]	L	--	--	--	--	5	0.3	--	--

1. Maximum emissions of total suspended particulate would occur in 1988, the year of expected construction activity.
2. The type of emission source refers to stationary (S), line (L), or area (A) sources.
3. One platform was assumed to be installed.
4. It was assumed that there would be 4 tugboats/platform installed. On an hourly basis, two were assumed to be stationary and two were assumed to be maneuvering near the platforms.
5. It was assumed that there would be one supply boat per platform installed. In the maximum hour case, it was assumed that the supply boat would be at platform for one-half an hour and in transit for one half an hour. On an annual basis, it was assumed that 90 percent of pollutants from the supply boat would be emitted while the source is mobile (line source) between the zone and San Francisco. Approximately 10 percent of the pollutants were assumed to be emitted while the source is stationary.
6. It was assumed that there would be one crew boat per platform installed. In the maximum hour case, the crew boat was assumed to be a line source from the zone to the nearest port with 10 percent of the total emissions occurring at each end of the route.
7. It was assumed that there would be 2 platforms drilling simultaneously. Emissions are on a "per platform" basis.
8. It was assumed that there would be 3 production platforms. Emissions are on a "per platform" basis.
9. It was assumed that there would be one floating production system in this year.
10. In Scenarios 1, 2 and 3, it was assumed that there would be two offshore storage and treatment (OS&T) facilities. In Scenario 1A, there would be none due to the addition of the onshore oil/gas processing plant. Emissions are on a "per OS&T" basis.
11. For Scenario 1A, the oil/gas processing plant would be located approximately 2 miles inland.

Table C-19 (continued)

12. On a maximum hour basis, it was assumed that four supply boats would be at platforms for one-half an hour and in transit back to the origin (San Francisco) for one-half an hour. Emissions for all four boats are given. On an annual basis it was assumed that 90 percent of pollutants from supply boats would be emitted while the sources are mobile (line sources) between the zone and San Francisco. Approximately 10 percent of the pollutants were assumed to be emitted while the sources are stationary; emissions would be distributed equally among the platforms.
13. On a maximum hour basis, it was assumed that three crew boats would be at the platforms for one-half an hour and in transit back to the origin (nearest port) for one-half an hour. Emissions for all three boats are given. On an annual basis, crew boats were assumed to be line sources from the zone to shore with 10 percent of total emissions occurring at each end of the route.
14. In Scenario 2, the ship would travel between the zone and the entrance to San Francisco Bay at 15 knots. In Scenario 3, the values given represent the time which would be required for the ship to travel between the zone and the Santa Cruz/Monterey County line.
15. Included as stationary emission sources are loading, hoteling and ballast pumping activities. The area sources would correspond to the maneuvering of the vessel near the platform.
16. These emissions would occur in San Francisco and include offloading, hoteling and refueling activities.
17. These emissions would occur in San Francisco and are produced as the ship moves at the reduced speed of 6 knots landward from the Golden Gate Bridge until it docks.

Table C-20. MAXIMUM CARBON MONOXIDE EMISSIONS - SANTA CRUZ ZONE[1]

Source/Activity	Type[2]	Scenario 1			Scenario 1A			Scenario 2			Scenario 3		
		lbs/ hr	lbs/ 8 hrs	lbs/ 12/hrs	lbs/ hr	lbs/ 8 hrs	lbs/ 12 hrs	lbs/ hr	lbs/ 8 hrs	lbs/ 12/hrs	lbs/ hr	lbs/ 8 hrs	lbs/ 12 hrs
A. Platform Installation[3]													
Derrick Barge	S	13	105	157	13	105	157	13	105	157	13	105	157
Tugboats[4]	S	13	103	154	13	103	154	13	103	154	13	103	154
Tugboats	A	13	103	155	13	103	155	13	103	155	13	103	155
Supply Boats[5]													
In Transit	L	5	31	45	5	31	45	5	13	45	5	13	45
At Platform	S	5	3	5	5	3	5	5	3	5	5	3	5
Crew Boats[6]													
In Transit	L	1	3	6	1	3	6	1	3	6	1	3	6
At Platform	S	1	0.4	0.7	1	0.4	0.7	1	0.4	0.7	1	0.4	0.7
In Port	S	--	0.4	0.7	--	0.4	0.7	--	0.4	0.7	--	0.4	0.7
B. Production Platform (with drilling)[7]													
Development Drilling	S	1	11	17	1	11	17	1	11	17	1	11	17
Power Generation	S	2	12	19	2	16	23	2	12	19	2	12	19
C. Production Platform (without drilling)[8]													
Power Generation	S	2	12	19	4	29	44	2	12	19	2	12	19
D. Floating Production System[9]													
Development Drilling	S	1	11	17	1	11	17	1	11	17	1	11	17
Power Generation	S	2	12	19	4	29	44	2	12	19	2	12	19
E. Offshore Storage & Treatment (OS&T)[10]													
Power Generation	S	3	26	38	--	--	--	22	15	2	22	15	2
Oil Processing	S	0.2	2	3	--	-	--	3	2	0.2	3	2	0.2
F. Onshore Gas Processing Plant[11]													
Oil Processing	S	--	--	--	0.3	2	3	--	--	--	--	--	--
Gas Processing (Power Generation)	S	--	--	--	0.3	2	3	--	--	--	--	--	--

Table C-20 (continued)

Source/Activity	Type[2]	Scenario 1			Scenario 1A			Scenario 2			Scenario 3		
		lbs/ hr	lbs/ 8 hrs	lbs/ 12/hrs	lbs/ hr	lbs/ 8 hrs	lbs/ 12 hrs	lbs/ hr	lbs/ 8 hrs	lbs/ 12/hrs	lbs/ hr	lbs/ 8 hrs	lbs/ 12 hrs
G. Supportive Activity													
Supply Boats[12]													
In Transit	L	14	122	184	14	122	184	14	122	184	14	122	184
At Platforms	S	14	14	20	14	14	20	14	14	20	14	14	20
Crew Boats[13]													
In Transit	L	3	11	15	3	11	15	3	11	15	3	11	15
At Platform	S	3	1	2	3	1	2	3	1	2	3	1	2
In Port	S	--	1	2	--	1	2	--	1	2	--	1	2
H. Tankers													
Sea Passage[14]	L	--	--	--	--	--	--	--	--	13	--	--	--
At OS&T[15]	S	--	--	--	--	--	--	6	51	64	0.1	1	2
	A	--	--	--	--	--	--	--	6	19	--	--	--
In Harbor	L	--	--	--	--	--	--	--	--	--	--	--	--
In Port	S	--	--	--	--	--	--	--	--	--	--	--	--

Table C-20 (continued)

1. Carbon monoxide emissions were assumed to be at the highest level in 1988.
2. The type of emission source refers to stationary (S), line (L), or area (A) sources.
3. One platform was assumed being installed.
4. It was assumed that there would be 4 tugboats/platform installed. On an hourly basis, two were assumed to be stationary and two were assumed to be maneuvering in the general vicinity of the platform. On an annual basis, all four tugboats were assumed to be maneuvering near the platforms.
5. It was assumed that there would be one supply boat per platform installed. In the maximum hour case, it was assumed that the supply boat would be at platform for one-half an hour and in transit for one half an hour. On an annual basis, it was assumed that 90 percent of pollutants from the supply boat would be emitted while the source is mobile (line source) between the zone and San Francisco. Approximately 10 percent of the pollutants were assumed to be emitted while the source is stationary; emissions would be distributed equally among the platforms.
6. It was assumed that there would be one crew boat per platform installed. In the maximum hour case, the crew boat was assumed to be at the platform for one-half an hour and in transit for one-half an hour. On an annual basis, the crew boat was assumed to be a line source from the zone to the nearest port with 10 percent of the total emissions occurring at each end of the route.
7. It was assumed that there would be 2 platforms drilling simultaneously. Emissions are on a "per platform" basis.
8. It was assumed that there would be 3 production platforms. Emissions are on a "per platform" basis.
9. It was assumed that there would be one floating production system in this year.
10. In Scenarios 1, 2 and 3, it was assumed that there would be one offshore storage and treatment (OS&T) facility. In Scenario 1A, there would be none due to the addition of the onshore oil/gas processing plant. Emissions are on a "per OS&T" basis.
11. For Scenario 1A, the oil/gas processing plant would be located approximately 2 miles inland.
12. On a maximum hour basis, it was assumed that six supply boats would be at platforms for one-half an hour and in transit back to the origin (Santa Barbara) for one-half an hour. Emissions for all six boats are given. On an annual basis, it was assumed that 90 percent of pollutants from the supply boat would be emitted while the source is mobile (line source) between the zone and San Francisco. Approximately 10 percent of the pollutants were assumed to be emitted while the source is stationary; emissions would be distributed equally among the platforms.
13. On a maximum hour basis, it was assumed that three crew boats would be at the platforms for one-half an hour and in transit back to origin (nearest port) for one-half an hour. Emissions for all three boats are given. On an annual basis, crew boats were assumed to be line sources from zone to shore with 10 percent of total emissions occuring at each end of the route.
14. For Scenario 2, the sea passage value would be for transit to the OS&T at 15 knots.
15. The hourly stationary emissions for Scenarios 2 and 3 at the OS&T would be due to loading of a tanker at the OS&T. For other averaging times, stationary emissions would result from hoteling, ballast purging, and loading (fuel combustion).

Table C-21. MAXIMUM HOURLY REACTIVE POLLUTANT EMISSIONS - SANTA MARIA ZONE[1]

Source/Activity	Type[2]	Scenario 1 HC	Scenario 1 NO_x	Scenario 1A HC	Scenario 1A NO_x	Scenario 2 HC	Scenario 2 NO_x	Scenario 3 HC	Scenario 3 NO_x
A. Production Platform (with drilling)[3]	S								
Development Drilling		0.5	6	0.5	6	0.5	6	0.5	6
Power Generation		1	14	1	12	1	14	1	14
Evaporative Losses		10	--	10	--	10	--	10	--
B. Production Platform (without drilling)[4]	S								
Power Generation		1	14	1	12	1	14	1	14
Evaporative Losses		10	--	10	--	10	--	10	--
C. Floating Production System (with drilling)[5]	S								
Subsea Drilling		0.5	6	0.5	6	0.5	6	0.5	6
Power Generation		1	14	2	41	1	14	1	14
Evaporative Losses		10	--	43	--	10	--	10	--
D. Floating Production System (without drilling)[6]	S								
Power Generation		1	14	2	41	1	14	1	14
Evaporative Losses	S	10	--	43	--	10	--	10	--
E. Offshore Storage and Treatment (OS&T)[7]	S								
Power Generation		3	30	--	--	1	12	1	12
Evaporative Losses		37	--	--	--	35	--	35	--
Oil Processing		0.3	3	--	--	0.3	3	0.3	3
Gas Processing		264	--	--	--	264	--	264	--
F. Alternate Gas Processing Platform[8]	S								
Power Generation		2	20	--	--	2	20	2	20
Evaporative Losses		14	--	--	--	14	--	14	--
Gas Processing		528	0.2	--	--	528	0.2	528	0.2
G. Subsea Pipelines[9]	L								
Evaporative Losses		66	--	66	--	33	--	33	--
H. Onshore Storage Tanks[10]	S								
Evaporative Losses		--	--	2	--	--	--	--	--

Table C-21 (continued)

Source/Activity	Type[2]	Scenario 1 HC	Scenario 1 NO_x	Scenario 1A HC	Scenario 1A NO_x	Scenario 2 HC	Scenario 2 NO_x	Scenario 3 HC	Scenario 3 NO_x
I. Onshore Oil/Gas Processing Plant[11]	S								
Oil Processing		--	--	0.5	7	--	--	--	--
Gas Compression		--	--	--	50	--	--	--	--
Gas Processing		--	--	1,056	--	--	--	--	--
J. Support Activities									
Supply Boats[12]									
In Transit	L	4	189	4	189	4	189	4	189
At Platform	S	4	189	4	189	4	189	4	189
In Port	S	--	--	--	--	--	--	--	--
Crew Boats[13]									
In Transit	L	0.5	23	0.5	23	0.5	23	0.5	23
At Platform	S	0.5	23	0.5	23	0.5	23	0.5	23
In Port	S	--	--	--	--	--	--	--	--
I. Tankers									
At OS&T[14]	S	--	--	--	--	799	2	799	10

1. Hourly reactive pollutant emissions were assumed to be at the highest level in 1991.
2. The type of emission source refers to stationary (S), or line (L) sources.
3. Emissions are given on a "per platform" basis. It was assumed that there would be two platforms drilling simultaneously.
4. Emissions are given on a "per platform" basis. It was assumed that there would be nine production platforms.
5. It was assumed that drilling would occur on one floating production system.
6. It was assumed that there would be one floating production system in which drilling does not occur.
7. It was assumed that there would be two offshore storage and treatment (OS&T) facilities in Scenarios 1, 2 and 3. Emissions are given on a "per OS&T" basis. There would be no OS&Ts in Scenario 1A due to the existence of an onshore oil/gas processing plant.
8. It was assumed that there would be one alternate gas processing platform in Scenarios 1, 2 and 3. There would be no gas processing platform in Scenario 1A due to the existence of an onshore oil/gas processing plant.

Table C-21 (continued)

9. In Scenarios 1 and 1A, there would be two subsea pipelines (one for gas and one for oil). There would be a subsea gas line only in Scenarios 2 and 3. The pipelines would be approximately sixteen miles long and may be considered a line source.
10. There would be two onshore 170,000 barrel crude oil storage tanks in Scenario 1A.
11. Based on the Scenario 1A supplied by BLM, the gas processing plant would be located approximately two miles inland.
12. For the maximum hour case, it was assumed that six boats are at platforms for one-half an hour and in transit back to the origin (Santa Barbara) for one-half an hour. Emissions are given for all six boats.
13. For the maximum hour case, it was assumed that four crewboats are at platforms for one-half an hour and in transit back to the origin (nearest port) for one-half an hour.
14. Emissions would be due to one hour of tanker loading at the OS&T.

Table C-22. MAXIMUM NITROGEN OXIDE EMISSIONS - SANTA MARIA ZONE[1]

Source/Activity	Type[2]	Scenario 1		Scenario 1A		Scenario 2		Scenario 3	
		lbs/hr	tons/yr	lbs/hr	tons/yr	lbs/hr	tons/yr	lbs/hr	tons/yr
A. Platform Installation[3]									
Derrick Barge	S	69	180	69	180	69	180	69	180
Tugboats[4]	S	86	--	86	--	86	--	86	--
Tugboats	A	86	451	86	451	86	451	86	451
Supply Boats[5]									
In Transit	L	32	124	32	124	32	124	32	124
At Platform	S	31	14	31	14	31	14	31	14
Crew Boats[6]									
In Transit	L	6	4	6	4	6	4	6	4
At Platform	S	5	0.6	5	0.6	5	0.6	5	0.6
In Port	S	--	0.6	--	0.6	--	0.6	--	0.6
B. Production Platform (with drilling)[7]	S								
Development Drilling		6	12	6	12	6	12	6	12
Power Generation		13	56	13	66	13	56	13	56
C. Production Platform (without drilling)[8]	S								
Power Generation		13	56	13	66	13	56	13	56
D. Floating Production System[9]	S								
Development Drilling		6	3	6	3	6	3	6	3
Power Generation		13	56	52	228	13	56	13	56
E. Offshore Storage & Treatment (OS&T)[10]	S								
Power Generation		27	117	--	--	12	53	12	53
Oil Processing		3	12	--	--	3	12	3	12
F. Alternative Gas Processing Platform[11]	S								
Power Generation		21	92	--	--	21	92	21	92
Gas Processing		--	0.6	--	--	--	0.6	--	0.6
G. Onshore Gas Processing Plant[12]	S								
Oil Processing		--	--	6	24	--	--	--	--
Gas Processing (Power Generation)		--	--	40	176	--	--	--	--

Table C-22 (continued)

Source/Activity	Type[2]	Scenario 1[1] lbs/hr	Scenario 1[1] tons/yr	Scenario 1A lbs/hr	Scenario 1A tons/yr	Scenario 2 lbs/hr	Scenario 2 tons/yr	Scenario 3 lbs/hr	Scenario 3 tons/yr
H. Supportive Activity									
Supply Boats[13]									
In Transit	L	189	992	189	992	189	992	189	992
At Platforms	S	189	110	189	110	189	110	189	110
Crew Boats[14]									
In Transit	L	23	35	23	35	23	35	23	35
At Platform	S	23	5	23	5	23	5	23	5
In Port	S	--	5	--	5	--	5	--	5
I. Tankers									
Sea Passage	L	--	--	--	--	42(15	81(16	--	10(22
At OS&T	A	--	--	--	--	--	4(17	--	3(17
	S	--	--	--	--	--	15(18	20(21	12(18
In Harbor	A	--	--	--	--	--	20(19	--	--
In Port	S	--	--	--	--	--	8(20	--	--

1. Nitrogen oxide emissions were assumed to be at the highest level in 1989.
2. The type of emission source refers to stationary (S), line (L), or area (A) sources.
3. Two platforms were assumed to be installed. Values are given on a "per platform" basis.
4. It was assumed that there would be four tugboats/platform installed. On an hourly basis, two were assumed to be stationary and two were assumed to be maneuvering in the general vicinity of the platform. On an annual basis, all four tugboats were assumed to be maneuvering near the platforms; stationary annual emissions were not considered significant.
5. It was assumed that there would be one supply boat per platform installed. In the maximum hour case, it was assumed that the supply boat would be at platform for one-half an hour and in transit for one half an hour. On an annual basis, it was assumed that 90 percent of the pollutants from the supply boat would be emitted while the source is mobile (line source) between the zone and Santa Barbara. Approximately 10 percent of the pollutants were assumed to be emitted while the source is stationary at the platform.
6. It was assumed that there would be one crew boat per platform installed. In the maximum hour case, the crew bpat was assumed to be at the platform for one-half an hour and in transit for one-half an hour. On an annual basis, 80 percent of the crew boat emissions were assumed to be a line source extending from the zone to the nearest port with 10 percent of the total emissions occurring at each end of the route as stationary sources
7. It was assumed that there would be four platforms drilling simultaneously. Emissions are on a "per platform" basis.
8. It was assumed that there would be five production platforms. Emissions are on a "per platform" basis.
9. It was assumed that there would be one floating production system in this year.

Table C-22 (continued)

10. In Scenarios 1, 2 and 3, it was assumed that there would be two offshore storage and treatment (OS&T) facilities. In Scenario 1A, there would be none due to the addition of the onshore oil/gas processing plant. Emissions are on a "per OS&T" basis.
11. In Scenarios 1, 2 and 3 it was assumed that there would be one alternate gas processing platform. In Scenario 1A, there would be no alternate gas processing platform due to the addition of the onshore gas/oil processing plant.
12. For Scenario 1A, the oil/gas processing plant would be located two miles inland near the Santa Maria River.
13. On a maximum hour basis, it was assumed that six supply-boats would be at platforms for one-half an hour and in transit back to the origin (Santa Barbara) for one-half an hour. Emissions for all six boats are given. On an annual basis, it was assumed that 90 percent of the pollutants from the supply boats would be emitted while the sources are mobile (line sources) between the zone and Santa Barbara. Approximately 10 percent of the pollutants would be emitted while the sources are stationary; emissions would be distributed equally among the platforms.
14. On a maximum hour basis, it was assumed that four crew boats would be at the platforms for one-half an hour and in transit back to origin (nearest port) for one-half an hour. Emissions for all four boats are given. On an annual basis, 80 percent of crewboat emissions were assumed to be line sources extending from the zone to shore with 10 percent of total emissions occurring at each end of the route as stationary sources.
15. Value would be for sea passage to the OS&T at 15 knots.
16. Total would be for sea passage from the zone to Los Angeles.
17. Emissions would occur from tanker maneuvering around OS&T.
18. Includes hoteling, pumping ballast, and loading at the OS&T.
19. Emissions would occur from assisting tugboats and tanker transit in Los Angeles Harbor.
20. Emissions would occur in Los Angeles Harbor.
21. Emissions would be due to the loading of two tankers at the OS&Ts for one hour.
22. Pollutants would be emitted from the zone to the southern Santa Barbara County border (70 nautical miles).

Table C-23. MAXIMUM SULFUR OXIDE EMISSIONS - SANTA MARIA ZONE[1]

Source/Activity	Type[2]	Scenario 1 lbs/hr	lbs/3 hrs	lbs/day	t/yr	Scenario 1A lbs/hr	lbs/3 hrs	lbs/day	t/yr	Scenario 2 lbs/hr	lbs/3 hrs	lbs/day	t/yr	Scenario 3 lbs/hr	lbs/3 hrs	lbs/day	t/yr
A. Production Platform (with drilling)[3]	S																
Development Drilling		3	10	78	8	3	10	78	8	3	10	78	8	3	10	78	8
Power Generation		7	22	175	32	9	27	212	39	7	22	175	32	7	22	175	32
B. Production Platform (without drilling)[4]	S																
Power Generation		7	22	175	32	9	27	212	39	7	22	175	32	7	22	175	32
C. Floating Production System (with drilling)[5]	S																
Subsea Drilling		3	10	78	2	3	10	78	2	3	10	78	2	3	10	78	2
Power Generation		7	22	175	32	20	60	483	88	7	22	175	32	7	22	175	32
D. Floating Production System (without drilling)[6]	S																
Power Generation		7	22	175	32	20	60	483	88	7	22	175	32	7	22	175	32
E. Offshore Storage and Treatment Facility (OS&T)[7]	S																
Power Generation		16	48	383	70	--	--	--	--	6	19	152	28	6	19	152	28
Gas Processing		13	40	321	59	--	--	--	--	13	40	321	59	13	40	321	59
F. Alternate Gas Processing Platform[8]	S																
Power Generation		11	33	261	48	--	--	--	--	11	33	261	48	11	33	261	48
Gas Processing		27	80	640	117	--	--	--	--	27	80	640	117	27	80	640	117
G. Onshore Oil/Gas Processing Plant[9]	S																
Gas Processing		--	--	--	--	54	164	1,285	235	--	--	--	--	--	--	--	--
H. Support Activity Supply Boats[10]																	
In Transit	L	13	54	434	54	13	54	434	54	13	54	434	54	13	54	434	54
At Platforms	S	13	14	108	14	13	14	108	14	13	14	108	14	13	14	108	14
I. Crew Boats[11]																	
In Transit	L	1	3	19	2	1	3	19	2	1	3	19	2	1	3	19	2
At Platforms	S	1	0.5	3	0.2	1	0.5	3	0.2	1	0.5	3	0.2	1	0.5	3	0.2
In Port	S	--	0.5	3	0.2	--	0.5	3	0.2	--	0.5	3	0.2	--	0.5	3	0.2
J. Tankers[12-15]																	
Sea Passage	L	--	--	--	--	--	--	--	--	265	795	1,060	--	--	--	--	73
At OS&T	A	--	--	--	--	--	--	--	--	--	119	357	38	--	--	--	32
	S	--	--	--	--	--	--	--	--	--	29	608	64	65	194	1,508	96
In Harbor	A	--	--	--	--	--	--	--	--	--	--	--	26	--	--	--	--
In Port	S	--	--	--	--	--	--	--	--	--	--	--	21	--	--	--	--

Table C-23 (continued)

1. Based on USGS mean resource estimate and development scenario for 1991.
2. The type of emission source refers to stationary (S), mobile (M), and line (L) sources.
3. It was assumed that there would be two platforms with drilling occurring on them simultaneously. Emissions are on a "per platform" basis.
4. It was assumed that there would be nine additional production platforms. Emissions are on a "per platform" basis.
5. It is expected that drilling would occur upon one floating production system.
6. It was assumed that there would be one floating production system without drilling.
7. It was assumed that there would be two offshore storage and treatment (OS&T) facilities in Scenarios 1, 2, and 3. There would not be any OS&T's in Scenario 1A due to the existence of an onshore oil/gas processing plant.
8. It was assumed that there would be one gas processing platform in Scenarios 1, 2, and 3. There would not be a gas processing platform in Scenario 1A due to the existence of an onshore oil/gas processing plant.
9. The oil/gas processing plant would be located near the Santa Maria River approximately two miles inland.
10. For the maximum hour scenario, it was assumed that six supply boats would be at the platforms for one-half an hour and in transit back to their origin (Santa Barbara) at 13 knots for one-half an hour. For other averaging times, it was assumed that 90 percent of the pollutants from supply boats would be emitted while the sources are mobile (line sources) between the zone and Santa Barbara. Approximately 10 percent of the pollutants would be emitted while the sources are stationary; emissions would be distributed equally among the platforms.
11. For the maximum hour scenario, it was assumed that four crew boats were at platforms for one-half an hour and in transit back to their origin (nearest port) for one-half an hour at 17 knots. For other averaging periods, 80 percent of the crew boat emissions were assumed to be line sources extending from the zone to the nearest port with 10 percent of total emissions occurring at each end of the route as stationary sources.
12. In Scenario 2, hourly emissions would occur from one hour of transit to the OS&T at 15 knots. For the three hour average, emissions would be composed of one hour of transit at 15 knots toward the OS&T, one hour of maneuvering around the OS&T and one hour of hoteling at the OS&T. Daily emissions would be composed of two hours of transit toward OS&T at 15 knots, two hours of transit away from the OS&T at 15 knots, three hours of maneuvering around the OS&T, ten hours of tanker loading, two hours of hoteling, and five hours of ballast numoinm.
13. Annual emissions for Scenario 2 would include stationary emissions from tanker operations at the OS&Ts, area source emissions from tanker maneuvering around OS&Ts, line source emissions from sea passage to Los Angeles, area source emissions from assisting tugboats and tanker transit in Los Angeles Harbor.
14. In Scenario 3, emissions for one and three hours would occur from tanker loading (due to fuel combustion) at the OS&T for one tanker. Daily emissions would occur from five hours of ballast discharge, two hours of hoteling and 17 hours of tanker loading for one tanker. For a worst case scenario, two tankers could operate simultaneously.
15. Annual emissions in Scenario 1 would include stationary emissions from tanker operations at the OS&Ts, area source emissions from maneuvering around OS&Ts, and sea passage emissions from the zone to the southern border of Santa Barbara County.

Table C-24. MAXIMUM TOTAL SUSPENDED PARTICULATE EMISSIONS - SANTA MARIA ZONE[1]

Source/Activity	Type[2]	Scenario 1		Scenario 1A		Scenario 2		Scenario 3	
		lbs/day	tons/yr	lbs/day	tons/yr	lbs/day	tons/yr	lbs/day	tons/yr
A. Platform Installation[3]									
Derrick Barge	S	100	11	100	11	100	11	100	11
Tugboats[4]	S	72	--	72	--	72	--	72	--
Tugboats[4]	A	72	20	72	20	72	20	72	20
Supply Boats[5]									
In Transit	L	50	5	50	5	50	5	50	5
At Platform	S	6	1	6	1	6	1	6	1
Crew Boats[6]									
In Transit	L	1	0.1	1	0.1	1	0.1	1	0.1
At Platform	S	--	--	--	--	--	--	--	--
In Port	S	--	--	--	--	--	--	--	--
B. Production Platform (with drilling)	S								
Development Drilling[7]		10	1	10	1	10	1	10	1
Power Generation		29	5	35	--	--	--	--	--
C. Production Platform (without drilling)[8]	S								
Power Generation		29	5	35	6	29	5	29	5
D. Floating Production System[9]	S								
Subsea Drilling		10	0.3	10	0.3	10	0.3	10	0.3
Power Generation		29	5	152	27	29	5	29	5
E. Offshore Storage & Treatment (OS&T)[10]	S								
Power Generation		65	12	--	--	28	5	28	5
Oil Processing		7	1	--	--	7	1	7	1

Table C-24 (continued)

Source/Activity	Type[2]	Scenario 1 lbs/day	Scenario 1 tons/yr	Scenario 1A lbs/day	Scenario 1A tons/yr	Scenario 2 lbs/day	Scenario 2 tons/yr	Scenario 3 lbs/day	Scenario 3 tons/yr
F. Alternate: Gas Processing Platform[11]	S								
Power Generation		47	9	--	--	47	9	47	9
G. Onshore Gas Processing Plant[12]	S								
Oil Processing		--	--	14	2	--	--	--	--
H. Supportive Activity									
Supply Boats[13]									
In Transit	L	373	43	373	43	373	43	373	43
At Platforms	S	42	5	42	5	42	5	42	5
Crew Boats[14]									
In Transit	L	20	2	20	2	20	2	20	2
At Platform	S	3	0.3	3	0.3	3	0.3	3	0.3
In Port	S	3	0.3	3	0.3	3	0.3	3	0.3
I. Tankers[15-18]									
Sea Passage	L	--	--	--	--	85	34	--	6
In Port	S	--	--	--	--	--	1	--	6
At Platform	S	--	--	--	--	36	3	90	

1. Based on the USGS mean resource estimate and development scenario for 1989.
2. The type of emission source refers to stationary (S), area (A), or line (L) sources.
3. It was assumed that there would be two platforms installed this year. Emissions are given on a "per platform" basis.
4. On a daily basis it was assumed that two tugboats would be associated with the derrick barge and can be consider as stationary sources. The other two tugboats were assumed to be maneuvering in the general vicinity of the platform being installed. On a yearly basis it was assumed that all tugboats would maneuver in the vicinity of the platform.
5. On a daily basis it was assumed that 90 percent of pollutants from supply boats would be emitted while the sources are mobile (line sources) between the zone and Santa Barbara. Approximately 10 percent of the pollutant were assumed to be emitted while the sources are stationary at the platform.
6. Approximately 80 percent of the pollutants from the crew boat were assumed to be emitted from line sources traveling between the zone and the nearest port with 10 percent of the total emissions occurring in port as a stationary source. The remaining 10 percent of emissions would occur as stationary sources at the platform.

Table C-24 (continued)

7. Emissions are given on a "per platform" basis. It was assumed that drilling would occur on four platforms simultaneously.
8. Emissions are given on a "per platform" basis. It was assumed that there would be five production platforms in addition to those where drilling occurs.
9. It was assumed that there would be one floating production system.
10. Two offshore storage and treatment facilities (OS&T) were assumed for Scenarios 1, 2, and 3. There would be no OS&T in Scenario 1A due to the existence of an onshore oil/gas processing plant. Emissions are given on a "per OS&T" basis.
11. It was assumed that there would be one gas processing platform in Scenarios 1, 2 and 3. There would not be a gas processing platform in Scenario 1A due to the existence of an onshore oil/gas processing plant.
12. Based on Scenario 1A supplied by BLM, the onshore oil/gas processing plant would be located two miles inland near the Santa Maria River.
13. It was assumed that there would be six supply boats. It was assumed that 90 percent of pollutants from supply boats would be emitted while the sources are mobile (line sources) between the zone and Santa Barbara. Approximately 10 percent of the pollutants were assumed to be emitted while the sources are stationary; emissions would be equally distributed among the platforms. Emissions are given for all boats.
14. It was assumed that 80 percent of pollutants from crew boats would be emitted while the sources are mobile (line sources) between the zone and the nearest port. Approximately 10 percent of the pollutants were assumed be emitted while the sources are stationary at the port and 10 percent while the sources are stationary at the platforms. Crew boat emissions occurring near the platforms would be distributed equally among the platforms.
15. Daily emissions in Scenario 2 would consist of two hours of sea transit to the OS&T, two hours of sea passage away from the OS&T, three hours of maneuvering about the OS&T, two hours of hoteling at the OS&T, five hours of ballast pumping at the OS&T, and ten hours of tanker loading at the OS&T.
16. Annual emissions in Scenario 2 would include offshore stationary emissions from tanker operations from the zone to Los Angeles, area source emissions from assisting tugboats and tanker transit in Los Angeles Harbor, and stationary emissions in Los Angeles from tanker operations.
17. Annual emissions in Scenario 3 would consist of stationary emissions from tanker operations at the OS&Ts and sea passage emissions from the zone to the southern border at Santa Barbara County.
18. Daily emissions from tankering operations in Scenario 3 would consist of emissions from two hours of hoteling at the OS&T, five hours of discharging ballast at the OS&T and 17 hours of tanker loading at the OS&T for one tanker. In a worst case scenario, two tankers may operate simultaneously.

Table C-25. MAXIMUM CARBON MONOXIDE EMISSIONS - SANTA MARIA ZONE[1]

		Scenario 1			Scenario 1A			Scenario 2			Scenario 3		
	Type[2]	lbs/hr	lbs/8 hrs	lbs/12 hrs	lbs/hr	lbs/8 hrs	lbs/12 hrs	lbs/hr	lbs/8 hrs	lbs/12 hrs	lbs/hr	lbs/8 hrs	lbs/12 hrs
A. Platform Installation[3]													
Derrick Barge	S	13	105	157	13	105	157	13	105	157	13	105	157
Tugboats[4]	S	13	103	155	13	103	155	13	103	155	13	103	155
Tugboats	A	13	103	155	13	103	155	13	103	155	13	103	155
Supply Boat[5]													
In Transit	L	5	68	85	5	68	85	5	68	85	5	68	85
At Platform	S	5	8	10	5	8	10	5	8	10	5	8	10
Crew Boat[6]													
In Transit	L	1	3	3	1	3	3	1	3	3	1	3	3
At Platform	S	1	0.5	0.5	1	0.5	0.5	1	0.5	0.5	1	0.5	0.5
In Port	S	--	0.5	0.5	--	0.5	0.5	--	0.5	0.5	--	0.5	0.5
B. Production Platform (with drilling)[7]	S												
Development Drilling		1	11	17	1	11	17	1	11	17	1	11	17
Power Generation		3	21	32	3	26	39	3	21	32	3	21	32
C. Production Platform (without drilling)[8]	S	3	21	32	3	26	39	3	21	32	3	21	32
Power Generation													
D. Floating Production System[9]	S												
Subsea Drilling		1	11	17	1	11	17	1	11	17	1	11	17
Power Generation		3	21	32	14	111	166	3	21	32	3	21	32
E. Offshore Storage and Treatment Facility (OS&T)[10]	S												
Power Generation		6	47	70	--	--	--	3	22	33	3	22	33
Oil Processing		0.5	4	7	--	--	--	0.5	4	7	0.5	4	7
F. Alternate Gas Processing Plant[11]	S												
Power Generation		5	38	57	--	--	--	5	38	57	5	38	57
G. Onshore Oil/Gas Processing Plant[12]	S												
Oil Processing		--	--	--	1	9	13	--	--	--	--	--	--

Table C-25 (continued)

	Type[2]	Scenario 1			Scenario 1A			Scenario 2			Scenario 3		
		lbs/hr	lbs/8 hrs	lbs/12 hrs	lbs/hr	lbs/8 hrs	lbs/12 hrs	lbs/hr	lbs/8 hrs	lbs/12 hrs	lbs/hr	lbs/8 hrs	lbs/12 hrs
H. Support Activities													
Supply Boats[13]													
In Transit	L	28	426	639	28	426	639	28	426	639	28	426	639
At Platforms	S	28	47	71	28	47	71	28	47	71	28	47	71
Crew Boats[14]													
In Transit	L	4	19	27	4	19	27	4	19	27	4	19	27
At Platforms	S	4	2	4	4	2	4	4	2	4	4	2	4
In Port	S	--	2	4	--	2	4	--	2	4	--	2	4
I. Tankers[15-17]													
Sea Passage	L	--	--	--	--	--	--	--	--	--	--	--	--
Onshore	S	--	--	--	--	--	--	--	--	--	--	--	--
Offshore	S	--	--	--	--	--	--	0.1	0.7	0.8	0.1	1	1

Table C-25 (continued)

1. Based on USGS mean resource estimate and development scenario for 1989.
2. The type of emission source refers to stationary (S), line (L), or area (A) sources.
3. It was assumed that there would be two platforms installed this year. Emissions are given on a "per platform installed" basis.
4. It was assumed that two tugboats would be associated with the derrick barge and can be considered as stationary sources. The other two tugboats were assumed to be maneuvering in the general vicinity of the platform being installed. Emissions are given for all four tugboats.
5. For the maximum hour scenario, it was assumed that the supply boat would be at the platform for one-half an hour and in transit back to point of origin (Santa Barbara) at 13 knots for one-half an hour. For other averaging periods, it was assumed that 90 percent of the pollutants from the supply boat would be emitted while the source is mobile (line source) between the zone and Santa Barbara. Approximately 10 percent of the pollutants would be emitted while the source is stationary at the platform.
6. For the maximum hour scenario, it was assumed that the crew boat would be at the platform for one-half an hour and in transit back to point of origin (nearest port) at 13 knots for one-half an hour. For other averaging periods, it was assumed that 80 percent of emissions would be a line source extending from the zone to the nearest port with 10 percent of the total emissions considered as stationary which would occur at the end of the route.
7. It was assumed that drilling would occur on four production platforms simultaneously. Emissions are given on a "per platform" basis.
8. It was assumed that there would be five additional production platforms. Emissions are given on a "per platform" basis.
9. It was assumed that there would be one floating production system.
10. It was assumed that there would be two offshore storage and treatment (OS&T) facilities in Scenarios 1, 2 and 3. There would not be any OS&T facilities in Scenario 1A due to the existence of an onshore oil/gas processing plant. Emissions are given on a "per OS&T" basis.
11. It was assumed that there would be one alternate gas processing platform in Scenarios 1, 2 and 3. There would not be a gas processing platform in Scenario 1A due to the existence of an onshore oil/gas processing plant.
12. Based on the Scenario 1A supplied by BLM, the oil/gas processing plant would be located near the Santa Maria River approximately two miles inland.
13. For the maximum hour case, it was assumed that six supply boats would be at platforms for one-half an hour and in transit back to point of origin (Santa Barbara) for one-half an hour at 13 knots. For other averaging periods, it was assumed that 90 percent of emissions would occur as a line source between Santa Barbara and the zone and with 10 percent of the total emissions assumed as stationary sources distributed equally among all the platforms. Emissions presented are for all boats.
14. For the maximum hour case, it was assumed that four crew boats would be at platforms for one-half an hour and in transit back to the point of origin (nearest port) for one-half an hour at 17 knots. For other averaging periods, it was assumed that 80 percent of emissions would occur as line sources between zone and the nearest port with 10 percent of the total emissions occurring in port as stationary sources. The remaining 10 percent of emissions would occur as stationary sources distributed equally among all platforms. Emissions are given for all boats.
15. Hourly emissions in Scenario 2 would be due to pumping ballast at the OS&T for one tanker.
16. Emissions for eight and twelve hour averaging periods in Scenario 2 would be due to pumping ballast and tanker loading at the OS&T for one tanker.
17. Emissions in Scenario 3 would be due to tanker loading at the OS&T for one tanker. In a worst case, two tankers would load at once.

Table C-26. REACTIVE POLLUTANT EMISSIONS FROM NON LEASE SALE NO. 53 OFFSHORE SOURCES - SANTA BARBARA CHANNEL[1]

Source	UTM Coordinates (km) E	UTM Coordinates (km) N	Emissions (lbs/hr) HC	Emissions (lbs/hr) NO_x
A. Existing Sources - 1975[2]				
Platform Holly	232	3,808	3	3
Other (a)	187	3,812	1	12
Other (b)	192	3,815	1	12
B. Estimated Future Sources - 1986[3]				
Platform Holly	232	3,808	6	25
Other (a)	187	3,812	0.2	4
Other (b)	192	3,815	0.2	4
Platform Hondo	208	3,804	79	264
Platform Secata Pescado	192	3,806	36	119
Santa Barbara Channel Platforms[4]			14	77
Santa Barbara Channel OS&Ts[5]			1,386	90
Tanker Operations[6] - Santa Barbara Channel Loading			1	20

Source: Aerovironment, Inc. (1977).

1. Only offshore activities west of Santa Barbara were considered.
2. Emission estimates presented in the Aerovironment report for 1975 are used and assumed to be applicable to 1976, the baseline year considered for this study.
3. Emissions estimated for 1986, the expected peak production year for Lease Sale 48, have been considered for this study. Emissions for other years are assumed to be lower, and are not listed in the Aerovironment report. The values for 1986 are assumed to be conservative when applied to 1991, the anticipated peak production year for the Santa Maria Zone.
4. Aerovironment assumed that seven platforms would be needed should all Lease Sale 48 tracts be let. As not all tracts were actually leased and only the western part of the channel is considered in this study, a smaller value of four platforms is assumed. Emissions for these platforms are given on a "per platform" basis.
5. In Aerovironment's report it was assumed that three offshore storage and loading facilities would be needed in the Santa Barbara Channel for the "normal tankering" scenario - two for Non Lease 48 activities and one for Lease Sale 48 activities - should all tracts be leased. As not all the tracts were leased, it is assumed that only two offshore storage and loading facilities would be needed, one for the Santa Barbara area and one for the Santa Ynez area.
6. Emissions presented for tankering operations are associated with tanker loading. Tanker transit emissions are not included. Aerovironment's total of 146,000 barrels of oil for average daily tankering is based on seven platforms producing oil in the Santa Barbara Channel. As only four are assumed to be located in the area considered for this study, this figure is assumed to be reduced to 125,000 barrels of oil per day. Santa Ynez tracts with platforms Hondo and Secate Pescado are assumed to have the same production level presented in Aerovironment's report. Aerovironment's assumption of tanker size (400,000 bbl) and loading rate(20,000 bbls/hr) were used. Based on the above assumptions, one tanker would be loaded every three days. It would take 20 hours to load each tanker. Tanker operation emissions are given for the western portion of Santa Barbara Channel so it should be noted that emissions would be divided between two storage and loading facilities assumed for this area.

Table C-27. NITROGEN OXIDE EMISSIONS FROM NON LEASE SALE NO. 53 OFFSHORE SOURCES - SANTA BARBARA CHANNEL[1]

Source	UTM Coordinates (km) E	UTM Coordinates (km) N	Emissions lbs/hr	Emissions tons/yr
A. Existing Sources - 1975[2]				
Platform Holly	232	3,808	3	13
Other (a)	187	3,812	12	52
Other (b)	192	3,815	12	52
B. Estimated Future Sources - 1986[3]				
Platform Holly	232	3,808	24	110
Other (a)	187	3,812	4	16
Other (b)	192	3,815	4	16
Platform Hondo	208	3,804	264	2,544
Platform Secata Pescado	192	3,806	119	1,145
Santa Barbara Channel Platforms[4]			77	740
Santa Barbara Channel OS&Ts[5]			90	867
Tanker Operations[6] - Santa Barbara Channel Loading			20	25

Source: Aerovironment, Inc. (1977).

1. Only offshore activities west of Santa Barbara were considered.
2. Emission estimates presented in the Aerovironment report for 1975 are used and assumed to be applicable to 1976, the baseline year considered for this study.
3. Emissions estimated for 1986, the expected peak production year for Lease Sale 48, have been considered for this study. Emissions for other years are assumed to be lower, and are not listed in the Aerovironment report. The values for 1986 are assumed to be conservative when applied to 1991, the anticipated peak production year for the Santa Maria Zone.
4. Aerovironment assumed that seven platforms would be needed should all Lease Sale 48 tracts be let. As not all tracts were actually leased and only the western part of the channel is considered in this study, a smaller value of four platforms is assumed. Emissions for these platforms are given on a "per platform" basis.
5. In Aerovironment's report it was assumed that three offshore storage and loading facilities would be needed in the Santa Barbara Channel for the "normal tankering" scenario - two for Non Lease 48 activities and one for Lease Sale 48 activities - should all tracts be leased. As not all the tracts were leased, it is assumed that only two offshore storage and loading facilities would be needed, one for the Santa Barbara area and one for the Santa Ynez area.
6. Emissions presented for tankering operations are associated with tanker loading. Tanker transit emissions are not included. Aerovironment's total of 146,000 barrels of oil for average daily tankering is based on seven platforms producing oil in the Santa Barbara Channel. As only four are assumed to be located in the area considered for this study, this figure is assumed to be reduced to 125,000 barrels of oil per day. Santa Ynez tracts with platforms Hondo and Secate Pescado are assumed to have the same production level presented in Aerovironment's report. Aerovironment's assumption of tanker size (400,000 bbl) and loading rate (20,000 bbls/hr) were used. Based on the above assumptions, one tanker would be loaded every three days. It would take 20 hours to load each tanker. Tanker operation emissions are given for the western portion of Santa Barbara Channel so it should be noted that emissions would be divided between two storage and loading facilities assumed for this area.

Table C-28. SULFUR OXIDE EMISSIONS FROM NON LEASE SALE NO. 53 OFFSHORE SOURCES SANTA BARBARA CHANNEL[1]

Source	UTM Coordinates (km) E	N	Emissions lbs/hr	lbs/3 hr	lbs/day	tons/yr
A. Existing Sources - 1975[2]						
Platform Holly						
Other (a)	232	3,808	1	3	27	5
Other (b)	187	3,812	0.3	1	6	1
	192	3,815	0.3	1	6	1
B. Estimated Future Sources - 1986[3]						
Platform Holly	232	3,808	0.2	7	58	11
Other (a)	187	3,812	0.1	0.3	3	0.5
Other (b)	192	3,815	0.1	0.3	3	0.5
Platform Hondo	208	3,804	31	94	755	138
Platform Secata Pescado	192	3,806	14	42	333	61
Santa Barbara Channel Platforms[4]			7	20	158	29
Santa Barbara Channel OS&Ts[5]			--	--	--	--
Tanker Operations[6] - Santa Barbara Channel Loading			167	502	3,344	203

Source: Aerovironment, Inc. (1977).

1. Only offshore activities west of Santa Barbara were considered.
2. Emission estimates presented in the Aerovironment report for 1975 are used and assumed to be applicable to 1976, the baseline year considered for this study.
3. Emissions estimated for 1986, the expected peak production year for Lease Sale 48, have been considered for this study. Emissions for other years are assumed to be lower, and are not listed in the Aerovironment report. The values for 1986 are assumed to be conservative when applied to 1991, the anticipated peak production year for the Santa Maria Zone.
4. Aerovironment assumed that seven platforms would be needed should all Lease Sale 48 tracts be let. As not all tracts were actually leased and only the western part of the channel is considered in this study, a smaller value of four platforms is assumed. Emissions for these platforms are given on a "per platform" basis.
5. In Aerovironment's report it was assumed that three offshore storage and loading facilities would be needed in the Santa Barbara Channel for the "normal tankering" scenario - two for Non Lease 48 activities and one for Lease Sale 48 activities - should all tracts be leased. As not all the tracts were leased, it is assumed that only two offshore storage and loading facilities would be needed, one for the Santa Barbara area and one for the Santa Ynez area.
6. Emissions presented for tankering operations are associated with tanker loading. Tanker transit emissions are not included. Aerovironment's total of 146,000 barrels of oil for average daily tankering is based on seven platforms producing oil in the Santa Barbara Channel. As only four are assumed to be located in the area considered for this study, this figure is assumed to be reduced to 125,000 barrels of oil per day. Santa Ynez tracts with platforms Hondo and Secate Pescado are assumed to have the same production level presented in Aerovironment's report. Aerovironment's assumption of tanker size (400,000 bbl) and loading rate (20,000 bbls/hr) were used. Based on the above assumptions, one tanker would be loaded every three days. It would take 20 hours to load each tanker. Tanker operation emissions are given for the western portion of Santa Barbara Channel so it should be noted that emissions would be divided between two storage and loading facilities assumed for this area.

Table C-29. CARBON MONOXIDE EMISSIONS FROM NON LEASE SALE NO. 53 OFFSHORE SOURCES - SANTA BARBARA CHANNEL[1]

Source	UTM Coordinates (km) E	N	Emissions lbs/hr	lbs/8 hr	lbs/12 hr
A. Existing Sources - 1975[2]					
Platform Holly	232	3,808	2	20	30
Other (a)	187	3,812	0.6	5	7
Other (b)	192	3,815	0.6	5	7
B. Estimated Future Sources - 1986[3]					
Platform Holly	232	3,808	5	42	63
Other (a)	187	3,812	0.2	2	3
Other (b)	192	3,815	0.2	2	3
Platform Hondo	208	3,804	68	540	810
Platform Secata Pescado	192	3,806	30	239	359
Santa Barbara Channel Platforms[4]			17	139	209
Santa Barbara Channel OS&Ts[5]			--	--	--
Tanker Operations[6] - Santa Barbara Channel Loading			1	8	12

Source: Aerovironment, Inc. (1977).

1. Only offshore activities west of Santa Barbara were considered.
2. Emission estimates presented in the Aerovironment report for 1975 are used and assumed to be applicable to 1976, the baseline year considered for this study.
3. Emissions estimated for 1986, the expected peak production year for Lease Sale 48, have been considered for this study. Emissions for other years are assumed to be lower, and are not listed in the Aerovironment report. The values for 1986 are assumed to be conservative when applied to 1991, the anticipated peak production year for the Santa Maria Zone.
4. Aerovironment assumed that seven platforms would be needed should all Lease Sale 48 tracts be let. As not all tracts were actually leased and only the western part of the channel is considered in this study, a smaller value of four platforms is assumed. Emissions for these platforms are given on a "per platform" basis.
5. In Aerovironment's report it was assumed that three offshore storage and loading facilities would be needed in the Santa Barbara Channel for the "normal tankering" scenario - two for Non Lease 48 activities and one for Lease Sale 48 activities - should all tracts be leased. As not all the tracts were leased, it is assumed that only two offshore storage and loading facilities would be needed, one for the Santa Barbara area and one for the Santa Ynez area.
6. Emissions presented for tankering operations are associated with tanker loading. Tanker transit emissions are not included. Aerovironment's total of 146,000 barrels of oil for average daily tankering is based on seven platforms producing oil in the Santa Barbara Channel. As only four are assumed to be located in the area considered for this study, this figure is assumed to be reduced to 125,000 barrels of oil per day. Santa Ynez tracts with platforms Hondo and Secate Pescado are assumed to have the same production level presented in Aerovironment's report. Aerovironment's assumption of tanker size (400,000 bbl) and loading rate (20,000 bbls/hr) were used. Based on the above assumptions, one tanker would be loaded every three days. It would take 20 hours to load each tanker. Tanker operation emissions are given for the western portion of Santa Barbara Channel so it should be noted that emissions would be divided between two storage and loading facilities assumed for this area.

Table C-30. TOTAL SUSPENDED PARTICULATES FROM NON LEASE SALE NO. 53 OFFSHORE SOURCES - SANTA BARBARA CHANNEL[1]

Source	UTM Coordinates (km) E	UTM Coordinates (km) N	Emissions lbs/day	Emissions tons/yr
A. Existing Sources - 1975[2]				
Platform Holly	232	3,808	27	5
Other (a)	187	3,812	6	1
Other (b)	192	3,815	6	1
B. Estimated Future Sources - 1986[3]				
Platform Holly	232	3,808	58	11
Other (a)	187	3,812	3	0.5
Other (b)	192	3,815	3	0.5
Platform Hondo	208	3,804	755	138
Platform Secata Pescado	192	3,806	333	61
Santa Barbara Channel Platforms[4]			169	31
Santa Barbara Channel OS&Ts[5]			--	--
Tanker Operations[6] - Santa Barbara Channel Loading			194	11

Source: Aerovironment, Inc. (1977).

1. Only offshore activities west of Santa Barbara were considered.
2. Emission estimates presented in the Aerovironment report for 1975 are used and assumed to be applicable to 1976, the baseline year considered for this study.
3. Emissions estimated for 1986, the expected peak production year for Lease Sale 48, have been considered for this study. Emissions for other years are assumed to be lower, and are not listed in the Aerovironment report. The values for 1986 are assumed to be conservative when applied to 1991, the anticipated peak production year for the Santa Maria Zone.
4. Aerovironment assumed that seven platforms would be needed should all Lease Sale 48 tracts be let. As not all tracts were actually leased and only the western part of the channel is considered in this study, a smaller value of four platforms is assumed. Emissions for these platforms are given on a "per platform" basis.
5. In Aerovironment's report it was assumed that three offshore storage and loading facilities would be needed in the Santa Barbara Channel for the "normal tankering" scenario - two for Non Lease 48 activities and one for Lease Sale 48 activities - should all tracts be leased. As not all the tracts were leased, it is assumed that only two offshore storage and loading facilities would be needed, one for the Santa Barbara area and one for the Santa Ynez area.
6. Emissions presented for tankering operations are associated with tanker loading. Tanker transit emissions are not included. Aerovironment's total of 146,000 barrels of oil for average daily tankering is based on seven platforms producing oil in the Santa Barbara Channel. As only four are assumed to be located in the area considered for this study, this figure is assumed to be reduced to 125,000 barrels of oil per day. Santa Ynez tracts with platforms Hondo and Secate Pescado are assumed to have the same production level presented in Aerovironment's report. Aerovironment's assumption of tanker size (400,000 bbl) and loading rate (20,000 bbls/hr) were used. Based on the above assumptions, one tanker would be loaded every three days. It would take 20 hours to load each tanker. Tanker operation emissions are given for the western portion of Santa Barbara Channel so it should be noted that emissions would be divided between two storage and loading facilities assumed for this area.

SURFACE WINDS

PERCENTAGE FREQUENCY OF WIND
DIRECTION AND SPEED
(FROM HOURLY OBSERVATIONS)

STATION: Eureka CA, Humboldt Bay P.P. (STATION NAME) Jan 1966 thru Dec 1967 (YEARS) ALL (MONTH)

ALL WEATHER (CLASS)

40°48', 124°12' (LOCATION)

ALL (HOURS [L.S.T.])

HEIGHT ABOVE GROUND

SPEED MPH / DIR.	1-3	4-7	8-12	13-18	19-24	> 25						%	MEAN WIND SPEED
N	0.7	3.7	6.1	4.7	2.2	1.1						18.4	12.7
NNE	0.6	2.1	2.7	1.2	0.3	0.1						6.9	9.6
NE	0.4	1.6	1.2	0.2	0.0							3.5	7.3
ENE	0.4	1.3	0.5	0.1	0.0							2.3	6.2
E	0.6	1.4	0.5	0.0								2.5	5.5
ESE	0.3	1.3	0.7	0.1	0.0	0.0						2.4	6.9
SE	0.2	1.0	0.8	0.9	0.5	0.5						3.9	13.3
SSE	0.3	1.0	1.0	2.1	1.4	0.9						6.7	15.7
S	0.5	1.5	2.1	1.9	0.6	0.2						6.7	11.3
SSW	0.6	1.9	2.3	1.0	0.4	0.2						6.5	10.1
SW	0.7	2.5	2.1	0.9	0.5	0.4						7.2	10.2
WSW	1.0	2.0	1.3	0.5	0.2	0.1						5.1	10.3
W	1.0	2.0	0.9	0.2	0.1	0.0						4.2	6.1
WNW	0.9	1.5	0.7	0.1	0.1	0.0						3.1	6.2
NW	0.9	2.2	1.5	0.3	0.1	0.1						5.0	7.3
NNW	0.7	2.9	3.5	1.8	0.5	0.1						9.6	9.9
CALM												5.9	9.6
5.9	9.9	30.0	27.8	15.9	6.9	3.8						100.0	

DATA from Pacific Gas and Electric Company

TOTAL NUMBER OF OBSERVATIONS 17,351

Figure C-1. PERCENTAGE FREQUENCY OF WIND DIRECTION AND SPEED, EUREKA, CA

Source: California Department of Water Resources (1978)

SURFACE WINDS

PERCENTAGE FREQUENCY OF WIND DIRECTION AND SPEED (FROM HOURLY OBSERVATIONS)

STATION: Point Arena, CA — YEARS: August 1970 thru July 1972 — MONTH: ALL

CLASS: ALL WEATHER — HOUR (L.S.T.): ALL

LOCATION: 38°56', 123°42', 238'

HEIGHT ABOVE GROUND: 16'

SPEED M.P.H. / DIR.	1-3	4-7	8-12	13-18	19-24	25-50						%	MEAN WIND SPEED
N	0.3	1.4	5.9	13.2	7.6	0.0						30.0	16.0
NNE	0.2	1.4	2.8	1.2	0.5	0.0						6.1	10.6
NE	0.3	1.3	1.2	0.0	0.0	0.0						2.9	6.8
ENE	0.2	0.7	0.3	0.0	0.0	0.0						1.3	5.8
E *	0.7	0.8	0.3	0.1	0.1	0.0						2.0	5.5
ESE	0.8	1.0	0.3	0.2	0.1	0.1						2.4	7.2
SE	1.0	2.6	3.6	3.0	1.7	1.5						13.4	13.3
SSE	0.5	1.2	0.9	0.9	0.5	0.3						4.3	11.9
S	0.6	0.8	0.4	0.3	0.2	0.1						2.4	9.4
SSW	0.2	0.4	0.2	0.1	0.1	0.0						1.0	9.1
SW	0.4	0.4	0.3	0.1	0.1	0.0						1.2	7.3
WSW	1.2	0.2	0.1	0.1	0.0	0.0						0.6	6.0
W	0.4	0.3	0.1	0.1	0.1	0.0						1.0	7.2
WNW	0.3	0.4	0.1	0.1	0.1	0.0						1.1	8.2
NW	0.3	1.1	1.0	0.7	0.4	0.0						3.6	10.3
NNW	0.2	1.4	4.4	8.7	8.3	3.6						26.6	17.6
CALM												0.1	14.0
0.1	6.9	15.4	22.0	28.7	19.7	7.4						99.9	

DATA FROM: Pacific Gas and Electric Company

TOTAL NUMBER OF OBSERVATIONS: 8,251

Figure C-2. PERCENTAGE FREQUENCY OF WIND DIRECTION AND SPEED, POINT ARENA, CA

Source: California Department of Water Resources (1978)

THE JOINT FREQUENCY FUNCTION FOR STABILITY CLASS 1

SECTORS	SPEED KNOTS	0 TO 3	4 TO 6	7 TO 10	11 TO 16	17 TO 21	> 21
1	N	.490000E-04	.680000E-04	.000000E+01	.000000E+01	.000000E+01	.000000E+01
2	NNE	.490000E-04	.680000E-04	.000000E+01	.000000E+01	.000000E+01	.000000E+01
3	NE	.117000E-03	.000000E+01	.000000E+01	.000000E+01	.000000E+01	.000000E+01
4	ENE	.000000E+01	.000000E+01	.000000E+01	.000000E+01	.000000E+01	.000000E+01
5	E	.490000E-04	.680000E-04	.000000E+01	.000000E+01	.000000E+01	.000000E+01
6	ESE	.490000E-04	.680000E-04	.000000E+01	.000000E+01	.000000E+01	.000000E+01
7	SE	.000000E+01	.000000E+01	.000000E+01	.000000E+01	.000000E+01	.000000E+01
8	SSE	.000000E+01	.000000E+01	.000000E+01	.000000E+01	.000000E+01	.000000E+01
9	S	.000000E+01	.000000E+01	.000000E+01	.000000E+01	.000000E+01	.000000E+01
10	SSW	.000000E+01	.000000E+01	.000000E+01	.000000E+01	.000000E+01	.000000E+01
11	SW	.000000E+01	.000000E+01	.000000E+01	.000000E+01	.000000E+01	.000000E+01
12	WSW	.000000E+01	.000000E+01	.000000E+01	.000000E+01	.000000E+01	.000000E+01
13	W	.000000E+01	.000000E+01	.000000E+01	.000000E+01	.000000E+01	.000000E+01
14	WNW	.000000E+01	.000000E+01	.000000E+01	.000000E+01	.000000E+01	.000000E+01
15	NW	.166000E-03	.680000E-04	.000000E+01	.000000E+01	.000000E+01	.000000E+01
16	NNW	.000000E+01	.000000E+01	.000000E+01	.000000E+01	.000000E+01	.000000E+01

THE JOINT FREQUENCY FUNCTION FOR STABILITY CLASS 2

1	.623000E-03	.212300E-02	.959000E-03	.000000E+01	.000000E+01	.000000E+01	.000000E+01
2	.129300E-02	.465800E-02	.193600E-02	.000000E+01	.000000E+01	.000000E+01	.000000E+01
3	.257500E-02	.787700E-02	.212300E-02	.000000E+01	.000000E+01	.000000E+01	.000000E+01
4	.267300E-02	.739700E-02	.157536E-02	.000000E+01	.000000E+01	.000000E+01	.000000E+01
5	.147800E-02	.223600E-02	.479000E-03	.000000E+01	.000000E+01	.000000E+01	.000000E+01
6	.749000E-03	.548000E-03	.274000E-03	.000000E+01	.000000E+01	.000000E+01	.000000E+01
7	.716000E-03	.205000E-03	.680000E-04	.000000E+01	.000000E+01	.000000E+01	.000000E+01
8	.596000E-03	.548000E-03	.680000E-04	.000000E+01	.000000E+01	.000000E+01	.000000E+01
9	.129700E-02	.548000E-03	.680000E-04	.000000E+01	.000000E+01	.000000E+01	.000000E+01
10	.237000E-03	.680000E-04	.137000E-03	.000000E+01	.000000E+01	.000000E+01	.000000E+01
11	.840000E-04	.680000E-04	.000000E+01	.000000E+01	.000000E+01	.000000E+01	.000000E+01
12	.321000E-03	.137000E-03	.411000E-03	.000000E+01	.000000E+01	.000000E+01	.000000E+01
13	.123000E-03	.411000E-03	.342000E-03	.000000E+01	.000000E+01	.000000E+01	.000000E+01
14	.825000E-03	.548000E-03	.479000E-03	.000000E+01	.000000E+01	.000000E+01	.000000E+01
15	.589000E-03	.479000E-03	.753000E-03	.000000E+01	.000000E+01	.000000E+01	.000000E+01
16	.369000E-03	.123300E-02	.137000E-03	.000000E+01	.000000E+01	.000000E+01	.000000E+01

THE JOINT FREQUENCY FUNCTION FOR STABILITY CLASS 3

1	.648000E-03	.179100E-02	.321900E-02	.479000E-03	.000000E+01	.000000E+01	.000000E+01
2	.544000E-03	.335600E-02	.753400E-02	.680000E-04	.000000E+01	.000000E+01	.000000E+01
3	.711000E-03	.353300E-02	.193600E-02	.680000E-04	.000000E+01	.000000E+01	.000000E+01
4	.671000E-03	.506800E-02	.123300E-02	.680000E-04	.000000E+01	.000000E+01	.000000E+01
5	.114800E-02	.335200E-02	.178100E-02	.000000E+01	.000000E+01	.000000E+01	.000000E+01
6	.556000E-03	.253400E-02	.191300E-02	.137000E-03	.000000E+01	.000000E+01	.000000E+01
7	.769000E-03	.145800E-02	.959000E-03	.000000E+01	.000000E+01	.000000E+01	.000000E+01
8	.437000E-03	.959000E-03	.274000E-03	.000000E+01	.000000E+01	.000000E+01	.000000E+01
9	.168100E-02	.680000E-03	.822000E-03	.342000E-03	.000000E+01	.000000E+01	.000000E+01
10	.150000E-04	.205000E-03	.192700E-02	.411000E-03	.342000E-03	.000000E+01	.000000E+01
11	.338000E-03	.274000E-03	.192700E-02	.274000E-03	.137000E-03	.680000E-04	.000000E+01
12	.200000E-04	.274000E-03	.123300E-02	.199600E-02	.205000E-03	.000000E+01	.000000E+01
13	.482000E-03	.548000E-03	.438400E-02	.554000E-02	.267900E-02	.680000E-03	.000000E+01
14	.435000E-03	.287700E-02	.822300E-02	.192700E-01	.671200E-02	.753000E-03	.000000E+01
15	.401000E-03	.143300E-02	.712300E-02	.582200E-02	.287700E-02	.342000E-03	.000000E+01
16	.114000E-03	.548000E-03	.137000E-02	.816000E-03	.000000E+01	.000000E+01	.000000E+01

Figure C-3. THE JOINT FREQUENCY FUNCTION FOR BODEGA BAY AND SANTA CRUZ ZONES. COMPILED FROM STAR DATA FOR STATION #23234, SAN FRANCISCO, CA

THE JOINT FREQUENCY FUNCTION FOR STABILITY CLASS 4

SPEED KNOTS	0 TO 3	4 TO 6	7 TO 10	11 TO 16	17 TO 21	> 21
1	.108000E-02	.301400E-02	.191800E-02	.438400E-02	.280300E-02	.685000E-03
2	.634000E-03	.301400E-02	.164400E-02	.116400E-02	.274000E-03	.000000E+01
3	.100600E-02	.301400E-02	.137000E-02	.876000E-03	.205000E-03	.685000E-04
4	.111600E-02	.342500E-02	.220800E-02	.890000E-03	.000000E+01	.000000E+01
5	.215800E-02	.595900E-02	.274000E-02	.123300E-02	.680000E-04	.000000E+01
6	.214000E-02	.664400E-02	.719200E-02	.246300E-02	.274000E-03	.000000E+01
7	.116300E-02	.568500E-02	.994100E-02	.618400E-02	.150700E-02	.274000E-03
8	.127100E-02	.520500E-02	.857500E-02	.452100E-02	.479900E-03	.880000E-04
9	.241700E-02	.554800E-02	.938300E-02	.100000E-01	.292500E-02	.219200E-02
10	.120200E-02	.356200E-02	.541100E-02	.575300E-02	.116400E-02	.479900E-03
11	.131600E-02	.315100E-02	.684700E-02	.424700E-02	.116400E-02	.680000E-04
12	.747000E-03	.431500E-02	.148630E-01	.168900E-01	.171200E-02	.342000E-03
13	.152700E-02	.472800E-02	.367120E-01	.777200E-01	.271920E-01	.842300E-02
14	.155300E-02	.655700E-02	.239940E-01	.839040E-01	.313410E-01	.588500E-02
15	.741000E-03	.253400E-02	.465800E-02	.156160E-01	.513700E-02	.411400E-03
16	.706000E-03	.411000E-03	.959000E-03	.107100E-02	.685000E-03	.680000E-04

THE JOINT FREQUENCY FUNCTION FOR STABILITY CLASS 5

1	.000000E+01	.102700E-02	.137000E-02	.000000E+01	.000000E+01	.000000E+01
2	.000000E+01	.102700E-02	.411000E-03	.000000E+01	.000000E+01	.000000E+01
3	.000000E+01	.685000E-03	.616000E-03	.000000E+01	.000000E+01	.000000E+01
4	.000000E+01	.548000E-03	.109600E-02	.000000E+01	.000000E+01	.000000E+01
5	.000000E+01	.116400E-02	.479000E-03	.000000E+01	.000000E+01	.000000E+01
6	.000000E+01	.191800E-02	.616000E-03	.000000E+01	.000000E+01	.000000E+01
7	.000000E+01	.274000E-02	.116400E-02	.000000E+01	.000000E+01	.000000E+01
8	.000000E+01	.352600E-02	.616000E-03	.000000E+01	.000000E+01	.000000E+01
9	.000000E+01	.554800E-02	.109600E-02	.000000E+01	.000000E+01	.000000E+01
10	.000000E+01	.226000E-02	.959000E-03	.000000E+01	.000000E+01	.000000E+01
11	.000000E+01	.232900E-02	.822000E-03	.000000E+01	.000000E+01	.000000E+01
12	.000000E+01	.232900E-02	.445200E-02	.000000E+01	.000000E+01	.000000E+01
13	.000000E+01	.369900E-02	.182350E-01	.000000E+01	.000000E+01	.000000E+01
14	.000000E+01	.541100E-02	.504790E-01	.000000E+01	.000000E+01	.000000E+01
15	.000000E+01	.184900E-02	.705500E-02	.000000E+01	.000000E+01	.000000E+01
16	.000000E+01	.616000E-03	.102700E-02	.000000E+01	.000000E+01	.000000E+01

THE JOINT FREQUENCY FUNCTION FOR STABILITY CLASS 6

1	.912000E-03	.205500E-02	.000000E+01	.000000E+01	.000000E+01	.000000E+01
2	.513000E-03	.822000E-03	.000000E+01	.000000E+01	.000000E+01	.000000E+01
3	.507000E-03	.753000E-03	.000000E+01	.000000E+01	.000000E+01	.000000E+01
4	.337000E-03	.109600E-02	.000000E+01	.000000E+01	.000000E+01	.000000E+01
5	.779000E-03	.685000E-03	.000000E+01	.000000E+01	.000000E+01	.000000E+01
6	.820000E-03	.184900E-02	.000000E+01	.000000E+01	.000000E+01	.000000E+01
7	.157300E-02	.353600E-02	.000000E+01	.000000E+01	.000000E+01	.000000E+01
8	.188000E-02	.479900E-02	.000000E+01	.000000E+01	.000000E+01	.000000E+01
9	.462800E-02	.835600E-02	.000000E+01	.000000E+01	.000000E+01	.000000E+01
10	.147400E-02	.527400E-02	.000000E+01	.000000E+01	.000000E+01	.000000E+01
11	.973000E-03	.458900E-02	.000000E+01	.000000E+01	.000000E+01	.000000E+01
12	.156300E-02	.472800E-02	.000000E+01	.000000E+01	.000000E+01	.000000E+01
13	.185400E-02	.107350E-01	.000000E+01	.000000E+01	.000000E+01	.000000E+01
14	.291300E-02	.246700E-01	.000000E+01	.000000E+01	.000000E+01	.000000E+01
15	.774000E-03	.297300E-02	.000000E+01	.000000E+01	.000000E+01	.000000E+01
16	.250000E-03	.123300E-02	.000000E+01	.000000E+01	.000000E+01	.000000E+01

Figure C-3 (Continued)

THE JOINT FREQUENCY FUNCTION FOR STABILITY CLASS 7

SPEED KNOTS	0 TO 3	4 TO 6	7 TO 10	11 TO 16	17 TO 21	> 21
1	.167800E-02	.000000E+01	.000000E+01	.000000E+01	.000000E+01	.000000E+01
2	.419900E-03	.000000E+01	.000000E+01	.000000E+01	.000000E+01	.000000E+01
3	.629900E-03	.000000E+01	.000000E+01	.000000E+01	.000000E+01	.000000E+01
4	.629900E-03	.000000E+01	.000000E+01	.000000E+01	.000000E+01	.000000E+01
5	.734900E-03	.000000E+01	.000000E+01	.000000E+01	.000000E+01	.000000E+01
6	.132300E-02	.000000E+01	.000000E+01	.000000E+01	.000000E+01	.000000E+01
7	.314600E-02	.000000E+01	.000000E+01	.000000E+01	.000000E+01	.000000E+01
8	.335600E-02	.000000E+01	.000000E+01	.000000E+01	.000000E+01	.000000E+01
9	.797900E-02	.000000E+01	.000000E+01	.000000E+01	.000000E+01	.000000E+01
10	.314600E-02	.000000E+01	.000000E+01	.000000E+01	.000000E+01	.000000E+01
11	.335600E-02	.000000E+01	.000000E+01	.000000E+01	.000000E+01	.000000E+01
12	.439900E-02	.000000E+01	.000000E+01	.000000E+01	.000000E+01	.000000E+01
13	.482400E-02	.000000E+01	.000000E+01	.000000E+01	.000000E+01	.000000E+01
14	.419500E-02	.000000E+01	.000000E+01	.000000E+01	.000000E+01	.000000E+01
15	.282100E-02	.000000E+01	.000000E+01	.000000E+01	.000000E+01	.000000E+01
16	.104900E-02	.000000E+01	.000000E+01	.000000E+01	.000000E+01	.000000E+01

Figure C-3 (Continued)

Source: Data derived by a STAR program using National Weather Service data collected on the San Francisco Pennisula (see text, Section A if Chapter VI).

SECTORS	SPEED KNOTS	0 TO 3	4 TO 6	7 TO 10	11 TO 16	17 TO 21	> 21
				THE JOINT FREQUENCY FUNCTION FOR STABILITY CLASS 1			
1	N	.122000E-03	.510000E-04	.000000E+01	.000000E+01	.000000E+01	.000000E+01
2	NNE	.148000E-03	.250000E-04	.000000E+01	.000000E+01	.000000E+01	.000000E+01
3	NE	.234000E-03	.250000E-04	.000000E+01	.000000E+01	.000000E+01	.000000E+01
4	ENE	.870000E-04	.000000E+01	.000000E+01	.000000E+01	.000000E+01	.000000E+01
5	E	.000000E+01	.000000E+01	.000000E+01	.000000E+01	.000000E+01	.000000E+01
6	ESE	.000000E+01	.000000E+01	.000000E+01	.000000E+01	.000000E+01	.000000E+01
7	SE	.870000E-04	.000000E+01	.000000E+01	.000000E+01	.000000E+01	.000000E+01
8	SSE	.000000E+01	.000000E+01	.000000E+01	.000000E+01	.000000E+01	.000000E+01
9	S	.000000E+01	.000000E+01	.000000E+01	.000000E+01	.000000E+01	.000000E+01
10	SSW	.000000E+01	.000000E+01	.000000E+01	.000000E+01	.000000E+01	.000000E+01
11	SW	.000000E+01	.000000E+01	.000000E+01	.000000E+01	.000000E+01	.000000E+01
12	WSW	.000000E+01	.000000E+01	.000000E+01	.000000E+01	.000000E+01	.000000E+01
13	W	.373000E-03	.127000E-03	.000000E+01	.000000E+01	.000000E+01	.000000E+01
14	WNW	.454000E-03	.152000E-03	.000000E+01	.000000E+01	.000000E+01	.000000E+01
15	NW	.541000E-03	.152000E-03	.000000E+01	.000000E+01	.000000E+01	.000000E+01
16	NNW	.270000E-03	.760000E-04	.000000E+01	.000000E+01	.000000E+01	.000000E+01
				THE JOINT FREQUENCY FUNCTION FOR STABILITY CLASS 2			
1		.842000E-03	.255000E-03	.102000E-03	.000000E+01	.000000E+01	.000000E+01
2		.513000E-03	.102000E-03	.510000E-04	.000000E+01	.000000E+01	.000000E+01
3		.126500E-02	.127000E-03	.102000E-03	.000000E+01	.000000E+01	.000000E+01
4		.116700E-02	.127000E-03	.510000E-04	.000000E+01	.000000E+01	.000000E+01
5		.348400E-02	.432000E-03	.510000E-04	.000000E+01	.000000E+01	.000000E+01
6		.288900E-02	.127000E-03	.250000E-04	.000000E+01	.000000E+01	.000000E+01
7		.121800E-02	.764000E-04	.000000E+01	.000000E+01	.000000E+01	.000000E+01
8		.169400E-03	.255000E-04	.102000E-03	.000000E+01	.000000E+01	.000000E+01
9		.111600E-03	.510000E-04	.250000E-04	.000000E+01	.000000E+01	.000000E+01
10		.700000E-05	.250000E-04	.000000E+01	.000000E+01	.000000E+01	.000000E+01
11		.136000E-03	.255000E-04	.510000E-04	.000000E+01	.000000E+01	.000000E+01
12		.416000E-03	.432000E-03	.279000E-03	.000000E+01	.000000E+01	.000000E+01
13		.218600E-02	.255400E-02	.331100E-02	.000000E+01	.000000E+01	.000000E+01
14		.204100E-02	.340200E-02	.444300E-02	.000000E+01	.000000E+01	.000000E+01
15		.217600E-02	.203100E-02	.225600E-02	.000000E+01	.000000E+01	.000000E+01
16		.966000E-03	.432000E-03	.305000E-03	.000000E+01	.000000E+01	.000000E+01
				THE JOINT FREQUENCY FUNCTION FOR STABILITY CLASS 3			
1		.323900E-03	.711000E-03	.838000E-03	.510000E-04	.000000E+01	.000000E+01
2		.182000E-03	.381000E-03	.482000E-03	.250000E-04	.000000E+01	.000000E+01
3		.244900E-03	.173000E-03	.203000E-03	.250000E-04	.000000E+01	.000000E+01
4		.225900E-03	.335000E-03	.250000E-04	.250000E-04	.000000E+01	.000000E+01
5		.125700E-02	.436700E-02	.127700E-02	.000000E+01	.000000E+01	.000000E+01
6		.175900E-02	.457600E-02	.170100E-02	.000000E+01	.000000E+01	.000000E+01
7		.724000E-03	.457000E-03	.178000E-03	.250000E-04	.000000E+01	.000000E+01
8		.370000E-04	.102000E-03	.203000E-03	.102000E-03	.000000E+01	.000000E+01
9		.112000E-03	.254000E-03	.432000E-03	.510000E-04	.000000E+01	.000000E+01
10		.420000E-04	.127000E-03	.254000E-03	.250000E-04	.000000E+01	.000000E+01
11		.137000E-03	.227000E-03	.432000E-03	.102000E-03	.000000E+01	.000000E+01
12		.207000E-03	.335000E-03	.134600E-02	.482000E-03	.736000E-04	.000000E+01
13		.973800E-03	.331100E-02	.123458E-01	.333200E-02	.127000E-03	.000000E+01
14		.109400E-02	.416400E-02	.181533E-01	.857600E-02	.635000E-03	.510000E-04
15		.622000E-03	.342300E-02	.157720E-01	.703300E-02	.294500E-02	.482000E-03
16		.861900E-03	.114300E-02	.241558E-01	.584000E-03	.220300E-03	.250000E-04

Figure C-4. THE JOINT FREQUENCY FUNCTION FOR SANTA MARIA ZONE. COMPILED FROM STAR DATA FOR STATION #93215, PT. ARGUELLO, CA

THE JOINT FREQUENCY FUNCTION FOR STABILITY CLASS 4

SPEED KNOTS	0 TO 3	4 TO 6	7 TO 10	11 TO 16	17 TO 21	> 21
1	.122490E-01	.867800E-02	.223905E-02	.231995E-02	.365000E-03	.250000E-04
2	.419400E-02	.162500E-02	.558395E-03	.191895E-02	.519000E-04	.000000E01
3	.333500E-02	.738300E-03	.760000E-04	.254995E-03	.000000E01	.000000E01
4	.333100E-02	.843000E-03	.182395E-03	.516295E-04	.000000E01	.000000E01
5	.105740E-01	.878860E-02	.358395E-02	.432995E-03	.152395E-03	.000000E01
6	.911600E-02	.980160E-02	.698295E-02	.216895E-02	.888900E-03	.203395E-03
7	.430795E-02	.269100E-02	.268295E-02	.367295E-02	.172795E-02	.534400E-03
8	.892995E-03	.468600E-03	.172695E-02	.276895E-02	.116895E-02	.330000E-03
9	.933095E-03	.584000E-03	.177700E-02	.195395E-02	.534995E-03	.127000E-03
10	.695295E-03	.835000E-03	.129595E-02	.124495E-02	.452995E-03	.500000E-04
11	.990695E-03	.889000E-03	.195895E-02	.186995E-02	.331995E-03	.000000E01
12	.238395E-02	.187995E-02	.253995E-02	.157495E-02	.127000E-03	.250000E-04
13	.787195E-02	.103895E-01	.140195E-01	.673495E-02	.351995E-03	.250000E-04
14	.143795E-01	.216740E-01	.341295E-01	.225495E-01	.213395E-02	.225000E-03
15	.279895E-01	.338595E-01	.573695E-01	.255395E-01	.195895E-01	.367395E-02
16	.294795E-01	.230995E-01	.184595E-01	.197595E-01	.507895E-02	.225000E-03

THE JOINT FREQUENCY FUNCTION FOR STABILITY CLASS 5

SPEED KNOTS	0 TO 3	4 TO 6	7 TO 10	11 TO 16	17 TO 21	> 21
1	.000000E01	.813000E-03	.284900E-02	.000000E01	.000000E01	.000000E01
2	.000000E01	.229000E-03	.139700E-02	.000000E01	.000000E01	.000000E01
3	.000000E01	.102000E-03	.432000E-03	.000000E01	.000000E01	.000000E01
4	.000000E01	.254000E-03	.127000E-03	.000000E01	.000000E01	.000000E01
5	.000000E01	.428600E-02	.583300E-02	.000000E01	.000000E01	.000000E01
6	.000000E01	.837900E-02	.132810E-01	.000000E01	.000000E01	.000000E01
7	.000000E01	.162500E-02	.738000E-03	.000000E01	.000000E01	.000000E01
8	.000000E01	.127000E-03	.250000E-04	.000000E01	.000000E01	.000000E01
9	.000000E01	.381000E-03	.250000E-04	.000000E01	.000000E01	.000000E01
10	.000000E01	.330990E-03	.510000E-04	.000000E01	.000000E01	.000000E01
11	.000000E01	.279900E-03	.178000E-03	.000000E01	.000000E01	.000000E01
12	.000000E01	.559000E-03	.305000E-03	.000000E01	.000000E01	.000000E01
13	.000000E01	.298200E-02	.127000E-02	.000000E01	.000000E01	.000000E01
14	.000000E01	.391000E-02	.601800E-02	.000000E01	.000000E01	.000000E01
15	.000000E01	.553500E-02	.157880E-01	.000000E01	.000000E01	.000000E01
16	.000000E01	.193000E-02	.794700E-02	.000000E01	.000000E01	.000000E01

THE JOINT FREQUENCY FUNCTION FOR STABILITY CLASS 6

SPEED KNOTS	0 TO 3	4 TO 6	7 TO 10	11 TO 16	17 TO 21	> 21
1	.146800E-02	.421500E-02	.000000E01	.000000E01	.000000E01	.000000E01
2	.377000E-03	.119300E-02	.000000E01	.000000E01	.000000E01	.000000E01
3	.507000E-03	.149200E-02	.000000E01	.000000E01	.000000E01	.000000E01
4	.561000E-03	.838000E-03	.000000E01	.000000E01	.000000E01	.000000E01
5	.377900E-02	.135840E-01	.000000E01	.000000E01	.000000E01	.000000E01
6	.694900E-02	.238640E-01	.000000E01	.000000E01	.000000E01	.000000E01
7	.234400E-02	.383400E-02	.000000E01	.000000E01	.000000E01	.000000E01
8	.451000E-03	.173000E-03	.000000E01	.000000E01	.000000E01	.000000E01
9	.279000E-03	.305990E-03	.000000E01	.000000E01	.000000E01	.000000E01
10	.162000E-03	.381990E-03	.000000E01	.000000E01	.000000E01	.000000E01
11	.631000E-03	.937000E-03	.000000E01	.000000E01	.000000E01	.000000E01
12	.745000E-03	.137790E-02	.000000E01	.000000E01	.000000E01	.000000E01
13	.291100E-02	.467290E-02	.000000E01	.000000E01	.000000E01	.000000E01
14	.270790E-02	.734400E-02	.000000E01	.000000E01	.000000E01	.000000E01
15	.460590E-02	.117380E-01	.000000E01	.000000E01	.000000E01	.000000E01
16	.293790E-02	.627290E-02	.000000E01	.000000E01	.000000E01	.000000E01

Figure C-4 (Continued)

THE JOINT FREQUENCY FUNCTION FOR STABILITY CLASS 7

SPEED KNOTS	0 TO 3	4 TO 6	7 TO 10	11 TO 16	17 TO 21	> 21
1	.403300E-02	.000000E+01	.000000E+01	.000000E+01	.000000E+01	.000000E+01
2	.176200E-02	.000000E+01	.000000E+01	.000000E+01	.000000E+01	.000000E+01
3	.343600E-02	.000000E+01	.000000E+01	.000000E+01	.000000E+01	.000000E+01
4	.231900E-02	.000000E+01	.000000E+01	.000000E+01	.000000E+01	.000000E+01
5	.874700E-02	.000000E+01	.000000E+01	.000000E+01	.000000E+01	.000000E+01
6	.139730E-01	.000000E+01	.000000E+01	.000000E+01	.000000E+01	.000000E+01
7	.737100E-02	.000000E+01	.000000E+01	.000000E+01	.000000E+01	.000000E+01
8	.974000E-03	.000000E+01	.000000E+01	.000000E+01	.000000E+01	.000000E+01
9	.649000E-03	.000000E+01	.000000E+01	.000000E+01	.000000E+01	.000000E+01
10	.510000E-03	.000000E+01	.000000E+01	.000000E+01	.000000E+01	.000000E+01
11	.225500E-02	.000000E+01	.000000E+01	.000000E+01	.000000E+01	.000000E+01
12	.375200E-02	.000000E+01	.000000E+01	.000000E+01	.000000E+01	.000000E+01
13	.839100E-02	.000000E+01	.000000E+01	.000000E+01	.000000E+01	.000000E+01
14	.618600E-02	.000000E+01	.000000E+01	.000000E+01	.000000E+01	.000000E+01
15	.658300E-02	.000000E+01	.000000E+01	.000000E+01	.000000E+01	.000000E+01
16	.431100E-02	.000000E+01	.000000E+01	.000000E+01	.000000E+01	.000000E+01

Figure C-4 (Continued)

Source: Data derived by a STAR program using National Weather Service data collected at Point Arguello (see text, Section A of Chapter VI).

Table C-31. STACK PARAMETERS USED IN LONG-TERM AVERAGE MODELING

Source	Stack Height (m)	Exhaust Gas Temperature (°C)	Stack Diameter (m)	Exit Velocity (m/sec)
Point Sources:[1]				
Platforms and Derrick Barge	30	140	0.5	24.5
Floating Platforms	5	140	0.5	24.5
Stationary Supply and Crew Boats, and Onshore Gas Processing Plants	3	150	0.5	24.5
Area Sources:[2]				
Tugs, Supply and Crew Boats in Transit	7	-	-	-

Notes: 1. Stationary source parameters were based on data for facilities in the Santa Barbara Channel (Woodward-Clyde, 1978).

2. Area sources take into account physical emissions height; but plume rise calculations are not performed by the CDM model. Physical stack height was taken from the Lease Sale No. 48 air quality study (AeroVironment, 1977).

Table C-32. STACK PARAMETERS USED IN SHORT-TERM AVERAGE MODELING

Source	Source Emissions Proportion (Percent)[1] NO_x	SO_x	PM	CO	Height (m)	Exhaust Gas Temperature (°C)	Volume Flow Rate (m /sec)	Diameter (m)	Velocity (m/sec)
Platforms:[1,2]									
Saturn Turbines	36.5	52.6	36.7	35.7	29	399	-	0.87	55.1
Centaur Turbines	62.6	46.8	61.7	60.7	29	177	-	2.79	19.8
Cat D-398 Diesel	0.9	0.6	1.4	3.6	29	100	-	0.30	5.0
Boats:[3]	100.	100.	100.	100.	10	427	5.3	-	-
Onshore Gas Processing Plant:[4]	100.	100.	100.	100.	3	149	0.83	-	-

Notes: 1. Platforms are assumed to generate emissions from three stacks in these specified proportions. Other sources are treated as having a single equivalent stack.

2. Platform parameters are taken from the Shell OCS Beta EIR-EA (USGS, 1978, Vol. II).

3. Tugboat parameters are used for tugboats and service ship emissions as well. Parameters are taken from the Wickland Fuels Terminal EIR (Woodward-Clyde, 1979).

4. Onshore facility parameters involve a slight simplification of parameters taken from the Platform Grace Pipeline EIR (Woodward-Clyde, 1978).

Table C-33. CDM MODELING EMISSIONS FOR THE EEL RIVER ZONE

Pollutant	Peak Year	Offshore Emissions Rate[1]	Area Sources As Percent Of Total[2]	Onshore Gas Plant Emissions Rate[1]	Reference Tables[3]
Nitrogen Oxides	1985	164(20.6)	7		C-2
Sulfur Oxides	1987	61.6(7.8)[4]	1	21.2(2.8)	C-3
Particulate Matter	1985	7.8(1.0)	38		C-4

Notes:

1. In pounds per hour and (grams per second).
2. All emissions were treated as a single point source. A first approximation to a more accurate answer consists in spreading this proportion of the offshore emissions rate, which represent mobile emissions, as a broad area source.
3. Emissions offshore were taken from these tables and summed.
4. This highest emission rate applies to Scenarios 1, 2, and 3 in Table C-3 and assumes offshore gas processing.

Table C-34. CDM MODELING EMISSIONS FOR THE POINT ARENA ZONE

Pollutant	Peak Year	Offshore Emissions Rate[1]	Area Sources As Percent of Total[2]	Onshore Gas Plant Emissions Rate[1]	Reference Tables[3]
Nitrogen Oxides	1989	103.9(13.1)[4]	31	19.9(2.50)	C-7
Sulfur Oxides	1989	135.5(17.1)[4]	52	21.0(2.65)	C-8
Particulate Matter	1989	15.8(2.0)	51	1.8(.23)	C-9

Notes: 1. In pounds per hour and (grams per second).

2. All emissions were treated as a single point source. A first approximation to a more accurate answer consists in spreading this proportion of the offshore emissions rate, which represent mobile emissions, as a broad area source.

3. Emissions offshore were taken from the tables and summed.

4. This highest offshore emission rate applies to Scenarios 1, 2, and 3 in Table C-7 and assumes offshore gas processing.

Table C-35. CDM MODELING EMISSIONS FOR THE BODEGA BAY ZONE

Pollutant	Peak Year	Offshore Emissions Rate[1]	Area Sources As Percent of Total[2]	Reference Tables[3]
Nitrogen Oxides	1985	158(19.9)	73	C-12
Sulfur Oxides	1987	12.4(1.57)	31	C-13
Particulate Matter	1985	8.1(1.02)	62	C-14

Notes: 1. In pounds per hour and (grams per second).

2. All emissions were treated as a single point source. A first approximation to a more accurate answer consists in spreading this proportion of the offshore emissions rate, which represent mobile emissions, as a broad area source.

3. Emissions offshore were taken from these tables and summed.

Table C-36. EMISSIONS USED IN CDM MODELING OF THE SANTA CRUZ ZONE[1]

Sources[2]	Nitrogen Oxides (grams per second)	Sulfur Oxides (grams per second)
Point Sources:		
1 (Production Platform)	1.09	0.86
2 (OS & T)	1.99	6.51
3 (Platform with Drilling)	1.50	1.18
4 (Production Platform)	1.09	0.86
5 (Platform Installation)	8.64	
6 (Floating Platform)	1.84	1.58
7 (Platform with Drilling)	1.50	1.18
8 (Production Platform)	1.09	0.86
9 (Gas Processing Plant)	1.24	1.99
Area Sources:[3]		
A & B (Tugboats, Supply Boats	4.04	0.081
C & D & Crew Boats)	7.19	0.144

Notes: 1. Emissions are for the estimated peak years (1988 for NO_2 and 1990 for SO_2). Data were derived from Tables C-17 and C-18.

2. Notations (1, 2, A, B, etc.) refer to symbols in Figure VI-1.

3. Area sources include most transport emissions associated with development and production support.

Table C-37. EMISSIONS USED IN CDM MODELING OF THE SANTA MARIA ZONE[1]

Sources[2]	Nitrogen Oxides (grams per second)	Sulfur Oxides (grams per second)
Point Sources:		
1 (Production Platform)	1.90	1.12
2 (Platform with Drilling)	2.25	1.35
3 (Production Platform)	1.90	1.12
4 (OS & T with Tanker)	6.34	6.76
5 (Production Platform)	1.90	1.12
6 (Gas Processing Plant)	2.67	4.75
7&8 (Platform with Drilling)	2.25	1.35
9 (Production Platform)	1.90	1.12
10 (OS & T)	5.15	3.71
11 (Platform with Drilling)	2.25	1.35
12 (Production Platform)	1.90	1.12
13 (Floating Platform)	6.65	2.59
14 (Onshore Gas Processing Plant)	5.76	6.76
Area Sources:[3]		
A & B (Tugboats, Supply	5.94	1.68
C Boats, and	10.56	2.99
D Crew Boats)	23.76	6.72

Notes: 1. Emissions are for the estimated peak years (1989 for NO_2 and 1991 for SO_2). Data were derived from Tables C-22 and C-23.

2. Notations (1, 2, A, B, etc.) refer to symbols in Figure VI-4.

3. Area sources include most transport emissions associated with development and production support.

Figures C-5 through C-35 summarize the modeling inputs used in defining the photochemical baselines. Baselines do not include potential Lease Sale No. 53 emissions. The baselines correspond closely to the discussion of trajectories in Section A-4 of Chapter IV. Figure C-5 is a key which explains the abbreviations generated by the computer which are found in each figure.

For each baseline, initial ambient air qualitiy is specified for a current (calibration) year and for a future impact year. The other input include hourly meteorology (wind speed, inversion height, and stability), the grid cell into which emissions are introduced, and non-OCS (ambient) emissions.

Graphs of the resulting evaluation of nitrogen dioxide and ozone concentrations during transport along each trajectory are presented in Appendix D (Modeling Results).

Figure C-5. KEY TO FIGURES C-6 THROUGH C-35

Key descriptors appear in the figures in the order of top to bottom as defined below.

KEY -

SOLAR - that is, insolation, which is proportional to K_1 in 1/min

WSPD - Wind speed in miles per hour

HINV - Height of the inversion in meters

STAR - Stability in Turner class (1=A)

EMISSIONS - Ambient in gm/sec/km^2

```
BLM OCS STUDY---EUREKA TRAJECTORY JUNE 22-1978 BASELINE
YEAR=  1978  STARTING AT   400.
INITIAL CONDITIONS (PPM)
            NO2      NO       O3       HC1      HC2      HC3      CO       SOX
AMBIENT     0.010    0.010    0.030    0.044    0.110    0.0      0.0      0.0
OCS         0.0      0.0      0.0      0.0      0.0      0.0      0.0      0.0

SOLAR WSPD HINV STAB LEVEL NO2      NO       HC1      HC2      HC3      CO       SOX
0.010  1.0  100.  4          0.       0.       0.       0.       0.       0.
0.013  2.0  100.  4          0.       0.       0.       0.       0.       0.
0.067  3.0  100.  4          0.       0.       0.       0.       0.       0.
0.168  3.0  100.  4          0.       0.       0.       0.       0.       0.
0.266  3.0  100.  4          0.       0.       0.       0.       0.       0.
8.328  4.0  100.  4          0.       0.       0.       0.       0.       0.
0.375  4.0  100.  4          0.       0.       0.       0.       0.       0.
0.397  4.0  100.  4          0.       0.       0.       0.       0.       0.
0.405  4.0  200.  4          0.       0.       0.       0.       0.       0.
```

Figure C-6. RAPT INPUT FOR EUREKA, 1978 BASELINE

BLM OCS STUDY---FORT BRAGG TRAJECTORY JUNE 22---1978 BASELINE
YEAR= 1978 STARTING AT 100.
INITIAL CONDITIONS (PPM)

	NO2	NO	O3	HC1	HC2	HC3	CO	SOX
AMBIENT	0.010	0.010	0.030	0.044	0.110	0.0	0.0	0.0
OCS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

SOLAR	WSPD	HINV	STAB	LEVEL	NO2	NO	HC1	HC2	HC3	CO	SOX
0.010	2.0	100.	4		0.	0.	0.	0.	0.	0.	
0.010	2.0	100.	4		0.	0.	0.	0.	0.	0.	
0.010	2.0	100.	4		0.	0.	0.	0.	0.	0.	
0.010	2.0	100.	4		0.	0.	0.	0.	0.	0.	
0.010	2.0	100.	4		0.	0.	0.	0.	0.	0.	
0.010	2.0	100.	4		0.	0.	0.	0.	0.	0.	
0.010	2.0	100.	4		0.	0.	0.	0.	0.	0.	
0.010	2.0	100.	4		0.	0.	0.	0.	0.	0.	
0.010	3.0	100.	4		0.	0.	0.	0.	0.	0.	
0.015	3.0	100.	4		0.	0.	0.	0.	0.	0.	
0.065	4.0	100.	4		0.	0.	0.	0.	0.	0.	
0.168	4.0	100.	4		0.	0.	0.	0.	0.	0.	
0.265	4.0	100.	4		0.	0.	0.	0.	0.	0.	
0.330	4.0	100.	4		0.	0.	0.	0.	0.	0.	
0.377	4.0	100.	4		0.	0.	0.	0.	0.	0.	
0.399	4.0	200.	4		0.	0.	0.	0.	0.	0.	

Figure C-7. RAPT INPUT DATA FOR FORT BRAGG, 1978 BASELINE

BLM OCS STUDY---BAY AREA TRAJECTORY 1-' AUG 5---1978 BASELINE
YEAR= 1978 STARTING AT 0.
INITIAL CONDITIONS (PPM)

	NO2	NO	O3	HC1	HC2	HC3	CO	SOX
AMBIENT	0.010	0.010	0.026	0.044	0.110	0.0	0.0	0.0
OCS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

SOLAR	WSPD	HINV	STAB LEVEL	NO2	NO	HC1	HC2	HC3	CO	SOX
0.010	5.0	100.	4	0.	0.	0.	0.	0.	0.	
0.010	6.0	110.	4	0.	0.	0.	0.	0.	0.	
0.010	8.0	110.	4	0.	0.	0.	0.	0.	0.	
0.010	8.0	120.	4	0.	0.	0.	0.	0.	0.	
0.010	7.0	120.	4	0.	0.	0.	0.	0.	0.	
0.012	4.0	120.	4	0.	0.	0.	0.	0.	0.	
0.097	4.0	120.	4	0.	0.	0.	0.	0.	0.	
0.202	3.0	130.	4	0.	2.	1.	3.	0.	43.	
0.288	6.0	80.	4	0.	5.	6.	20.	1.	58.	
0.356	4.0	100.	4	0.	1.	1.	3.	0.	12.	
0.393	6.0	150.	4	0.	1.	2.	6.	0.	28.	
0.420	6.0	180.	4	0.	0.	0.	0.	0.	0.	
0.424	5.0	200.	4	0.	0.	0.	0.	0.	1.	
0.420	6.0	500.	4	0.	0.	0.	0.	0.	0.	
0.393	5.0	600.	4	0.	0.	0.	0.	0.	0.	
0.356	9.0	600.	4	0.	0.	0.	0.	0.	0.	

Figure C-8. RAPT INPUT FOR BAY AREA NO. 1, 1978 BASELINE

BLM OCS STUDY---BAY AREA TRAJECTORY 2-JULY 26---1973 BASELINE
YEAR= 1973 STARTING AT 400.
INITIAL CONDITIONS (PPM)

	NO2	NO	O3	HC1	HC2	HC3	CO	SOX
AMBIENT	0.020	0.010	0.030	0.132	0.330	0.0	0.0	0.0
OCS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

SOLAR	WSPD	HINV	STAB	LEVEL	NO2	NO	HC1	HC2	HC3	CO	SOX
0.010	6.0	120.	4		0.	0.	0.	0.	0.	0.	
0.010	8.0	200.	4		0.	0.	0.	0.	0.	0.	
0.010	6.0	240.	4		0.	0.	0.	0.	0.	0.	
0.036	4.0	120.	4		0.	0.	0.	0.	0.	0.	
0.127	6.0	60.	4		0.	0.	0.	1.	0.	9.	
0.217	4.0	30.	6		0.	1.	1.	3.	0.	17.	
0.277	3.0	60.	4		0.	1.	1.	3.	0.	13.	
0.309	12.0	100.	4		0.	1.	1.	4.	0.	15.	
0.320	9.0	150.	4		0.	2.	2.	9.	0.	21.	
0.309	10.0	150.	4		0.	0.	0.	0.	0.	0.	
0.277	13.0	200.	4		0.	0.	0.	0.	0.	3.	

Figure C-9. RAPT INPUT FOR BAY AREA NO. 2, 1973 BASELINE

BLM OCS STUDY---BAY AREA TRAJECTORY 3-AUG 22---1974 BASELINE
YEAR= 1974 STARTING AT 100.
INITIAL CONDITIONS (PPM)

	NO2	NO	O3	HC1	HC2	HC3	CO	SOX
AMBIENT	0.010	0.010	0.030	0.044	0.110	0.0	0.0	0.0
OCS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

SOLAR	WSPD	HINV	STAB	LEVEL	NO2	NO	HC1	HC2	HC3	CO	SOX
0.010	4.0	100.	4		0.	0.	0.	0.	0.	0.	
0.010	4.0	90.	4		0.	0.	0.	0.	0.	0.	
0.010	4.0	80.	4		0.	0.	0.	0.	0.	0.	
0.010	4.0	80.	4		0.	0.	0.	0.	0.	0.	
0.021	6.0	70.	4		0.	0.	0.	0.	0.	0.	
0.061	11.0	60.	4		0.	0.	0.	0.	0.	0.	
0.164	8.0	50.	4		0.	0.	0.	0.	0.	0.	
0.264	6.0	100.	4		0.	0.	0.	0.	0.	0.	
0.329	6.0	200.	4		0.	0.	0.	0.	0.	0.	
0.377	4.0	300.	4		0.	1.	0.	2.	0.	12.	
0.400	4.0	400.	4		0.	0.	0.	0.	0.	0.	
0.409	12.0	600.	4		0.	0.	0.	0.	0.	0.	
0.400	6.0	800.	4		0.	0.	0.	0.	0.	1.	
0.377	7.0	800.	4		0.	0.	0.	0.	0.	0.	

Figure C-10. RAPT INPUT FOR BAY AREA NO. 3, 1974 BASELINE

BLM OCS STUDY---BAY AREA TRAJECTORY 4-JULY 26---1973 BASELINE
YEAR= 1973 STARTING AT 300.
INITIAL CONDITIONS (PPM)

	NO2	NO	O3	HC1	HC2	HC3	CO	SOX
AMBIENT	0.010	0.010	0.030	0.132	0.330	0.0	0.0	0.0
OCS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

SOLAR	WSPD	HINV	STAB	LEVEL	NO2	NO	HC1	HC2	HC3	CO	SOX
0.010	14.0	50.	5		0.	0.	0.	0.	0.	0.	
0.010	13.0	60.	5		0.	0.	0.	0.	0.	0.	
0.010	12.0	70.	4		0.	0.	0.	0.	0.	0.	
0.010	9.0	80.	4		0.	0.	0.	0.	0.	0.	
0.034	6.0	90.	4		0.	0.	0.	0.	0.	0.	
0.123	6.0	100.	4		0.	0.	0.	0.	0.	0.	
0.211	6.0	120.	4		0.	0.	0.	1.	0.	4.	
0.272	3.0	120.	4		0.	1.	2.	0.	0.	1.	
0.303	5.0	120.	4		0.	0.	0.	0.	0.	0.	
0.314	7.0	150.	4		0.	0.	0.	0.	0.	0.	
0.303	9.0	200.	4		0.	1.	0.	1.	0.	6.	
0.272	17.0	400.	4		0.	0.	0.	1.	0.	5.	

Figure C-11. RAPT INPUT FOR BAY AREA NO. 4, 1973 BASELINE

BLM OCS STUDY---BAY AREA TRAJECTORY 5 — SEPT 9---1976 BASELINE
YEAR= 1976 STARTING AT 100.
INITIAL CONDITIONS (PPM)

	NO2	NO	O3	HC1	HC2	HC3	CO	SOX
AMBIENT	0.080	0.030	0.030	0.440	1.100	0.0	0.0	0.0
OCS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

SOLAR	WSPD	HINV	STAB LEVEL	NO2	NO	HC1	HC2	HC3	CO	SOX
0.010	3.0	50.	5	0.	0.	0.	0.	0.	0.	
0.010	3.0	60.	5	0.	0.	0.	0.	0.	0.	
0.010	3.0	70.	4	0.	0.	0.	0.	0.	0.	
0.010	2.0	80.	4	0.	0.	0.	0.	0.	0.	
0.010	5.0	90.	4	0.	0.	0.	0.	0.	0.	
0.010	4.0	100.	4	0.	0.	0.	0.	0.	0.	
0.010	4.0	110.	4	0.	0.	0.	0.	0.	0.	
0.073	5.0	120.	4	0.	0.	0.	0.	0.	0.	
0.156	3.0	120.	4	0.	0.	0.	0.	0.	0.	
0.222	5.0	120.	4	0.	0.	0.	0.	0.	0.	
0.261	7.0	200.	4	0.	0.	0.	0.	0.	0.	
0.271	10.0	250.	4	0.	0.	0.	1.	0.	4.	
0.261	10.0	400.	4	0.	0.	0.	0.	0.	1.	
0.222	9.0	500.	4	0.	0.	0.	0.	0.	0.	
0.155	7.0	700.	4	0.	0.	0.	0.	0.	0.	
0.073	9.0	900.	4	0.	0.	0.	0.	0.	3.	
0.010	11.0	1000.	4	0.	0.	0.	0.	0.	5.	

Figure C-12. RAPT INPUT DATA FOR BAY AREA NO. 5, 1976 BASELINE

BLM OCS STUDY---BAY AREA TRAJECTORY 6-' AUG 5---1978 BASELINE
YEAR= 1978 STARTING AT 0.
INITIAL CONDITIONS (PPM)

	NO2	NO	O3	HC1	HC2	HC3	CO	SOX
AMBIENT	0.010	0.010	0.030	0.440	1.100	0.0	0.0	0.0
OCS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

SOLAR	WSPD	HINV	STAB	LEVEL	NO2	NO	HC1	HC2	HC3	CO	SOX
0.010	5.0	100.	4		0.	0.	0.	0.	0.	0.	
0.010	10.0	110.	4		0.	0.	0.	0.	0.	0.	
0.010	7.0	110.	4		0.	0.	0.	0.	0.	0.	
0.010	8.0	120.	4		0.	0.	0.	0.	0.	0.	
0.010	7.0	120.	4		0.	0.	0.	0.	0.	0.	
0.012	4.0	120.	4		0.	1.	0.	1.	0.	8.	
0.097	3.0	100.	4		0.	2.	1.	2.	1.	37.	
0.202	4.0	80.	4		0.	2.	2.	6.	0.	59.	
0.288	5.0	120.	4		0.	0.	0.	0.	0.	1.	
0.356	6.0	120.	4		0.	0.	0.	0.	0.	0.	
0.393	4.0	120.	4		0.	0.	0.	0.	0.	1.	
0.420	5.0	200.	4		0.	0.	1.	2.	0.	6.	
0.424	7.0	300.	4		0.	0.	1.	3.	0.	7.	
0.420	6.0	400.	4		0.	0.	2.	6.	0.	21.	
0.393	5.0	500.	4		0.	3.	2.	6.	0.	37.	
0.356	4.0	600.	4		0.	1.	1.	3.	0.	27.	
0.288	4.0	300.	4		0.	0.	0.	0.	0.	2.	

Figure C-13. RAPT INPUT DATA FOR BAY AREA NO. 6, 1978 BASELINE

BLM OCS STUDY---BAY AREA TRAJECTORY 7- SEPT 9---1976 BASELINE
YEAR= 1976 STARTING AT 100.
INITIAL CONDITIONS (PPM)

	NO2	NO	O3	HC1	HC2	HC3	CO	SOX
AMBIENT	0.010	0.030	0.030	0.132	0.330	0.0	0.0	0.0
OCS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

SOLAR	WSPD	HINV	STAB LEVEL	NO2	NO	HC1	HC2	HC3	CO	SOX
0.010	4.0	70.	4	0.	0.	0.	0.	0.	0.	
0.010	5.0	80.	4	0.	0.	0.	0.	0.	0.	
0.010	4.0	80.	4	0.	0.	0.	0.	0.	0.	
0.010	4.0	90.	4	0.	0.	0.	0.	0.	0.	
0.010	5.0	100.	4	0.	0.	0.	0.	0.	0.	
0.010	5.0	110.	4	0.	0.	0.	0.	0.	0.	
0.010	6.0	120.	4	0.	0.	0.	0.	0.	0.	
0.078	6.0	120.	4	0.	0.	0.	0.	0.	0.	
0.162	14.0	120.	4	0.	0.	0.	0.	0.	0.	
0.230	10.0	120.	4	0.	0.	0.	0.	0.	0.	
0.266	7.0	150.	4	0.	0.	0.	0.	0.	1.	
0.277	7.0	200.	4	0.	0.	0.	0.	0.	0.	
0.266	5.0	400.	4	0.	0.	0.	2.	0.	7.	
0.230	8.0	300.	4	0.	1.	0.	1.	0.	6.	
0.162	7.0	600.	4	0.	1.	1.	2.	0.	10.	
0.078	7.0	800.	4	0.	0.	0.	0.	0.	4.	

Figure C-14. RAPT DATA INPUT FOR BAY AREA NO. 7, 1976 BASELINE

BLM OCS STUDY---SCOTTS VALLEY TRAJECTOEY SEPT 9---1976 BASELINE
YEAR= 1976 STARTING AT 300.
INITIAL CONDITIONS (PPM)

	NO2	NO	O3	HC1	HC2	HC3	CO	SOX
AMBIENT	0.140	0.080	0.010	0.660	1.650	0.0	0.0	0.0
OCS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

SOLAR	WSPD	HINV	STAB	LEVEL	NO2	NO	HC1	HC2	HC3	CO	SOX
0.010	10.0	80.	4		0.	0.	0.	0.	0.	0.	
0.010	7.0	80.	4		0.	0.	0.	0.	0.	0.	
0.010	10.0	100.	4		0.	0.	0.	0.	0.	0.	
0.010	5.0	110.	4		0.	0.	0.	0.	0.	0.	
0.010	6.0	120.	4		0.	0.	0.	0.	0.	0.	
0.078	4.0	120.	4		0.	0.	0.	0.	0.	0.	
0.162	7.0	120.	4		0.	0.	0.	0.	0.	0.	
0.230	6.0	150.	4		0.	0.	0.	0.	0.	0.	
0.266	8.0	200.	4		0.	0.	0.	0.	0.	0.	
0.277	6.0	300.	4		0.	0.	0.	0.	0.	0.	
0.266	7.0	500.	4		0.	0.	0.	0.	0.	0.	
0.230	8.0	500.	4		0.	0.	0.	0.	0.	0.	
0.162	5.0	600.	4		0.	0.	0.	0.	0.	0.	
0.078	5.0	400.	4		0.	0.	0.	0.	0.	0.	
0.010	4.0	200.	4		0.	0.	0.	2.	0.	0.	

Figure C-15. RAPT INPUT DATA FOR SCOTTS BALLEY, 1976 BASELINE

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BLM OCS STUDY---SALINAS TRAJECTORY AUG 5---1978 BASELINE
YEAR=   197  STARTING AT   300.
INITIAL CONDITIONS (PPM)
            NO2      NO       O3       HC1      HC2      HC3      CO       SOX
AMBIENT    0.002    0.015    0.030    0.009    0.110    0.0      0.300    0.0
OCS        0.0      0.0      0.0      0.0      0.0      0.0      0.0      0.0

SOLAR WSPD HINV STAB LEVEL NO2      NO       HC1      HC2      HC3      CO       SOX
0.010 17.0  100.  4          0.       0.       0.       0.       0.       0.
0.010 20.0  100.  4          0.       0.       0.       0.       0.       0.
0.012 16.0  100.  4          0.       0.       0.       0.       0.       0.
0.097 17.0  100.  4          0.       0.       0.       0.       0.       0.
0.202 19.0  100.  4          0.       0.       0.       0.       0.       0.
0.288 18.0  100.  4          0.       0.       0.       0.       0.       0.
0.356 20.0  100.  4          0.       0.       0.       0.       0.       0.
0.393 18.0    0. 40          0.       0.      -0.       0.       0.       0.
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Figure C-16. RAPT INPUT DATA FOR SALINAS, 1978 BASELINE

BLM OCS STUDY---MONTEREY TRAJECTORY AUG 5---1978 BASELINE
YEAR= 197 STARTING AT 300.
INITIAL CONDITIONS (PPM)

	NO2	NO	O3	HC1	HC2	HC3	CO	SOX
AMBIENT	0.010	0.015	0.030	0.009	0.022	0.0	0.300	0.0
OCS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

SOLAR	WSPD	HINV	STAB	LEVEL	NO2	NO	HC1	HC2	HC3	CO	SOX
0.010	17.0	100.	4		0.	0.	0.	0.	0.	0.	
0.010	20.0	100.	4		0.	0.	0.	0.	0.	0.	
0.012	16.0	100.	4		0.	0.	0.	0.	0.	0.	
0.097	17.0	100.	4		0.	0.	0.	0.	0.	0.	
0.202	19.0	100.	4		0.	0.	0.	0.	0.	0.	
0.288	18.0	100.	4		0.	0.	0.	0.	0.	0.	
0.356	20.0	100.	4		0.	0.	0.	0.	0.	0.	
0.393	1.0	0.	0		0.	0.	-1.	-0.	0.	0.	

Figure C-17. RAPT INPUT DATA FOR MONTEREY, 1978 BASELINE

BLM OCS STUDY---NIPOMO TRAJECTORY SEPT 29---1978 BASELINE
YEAR= 1978 STARTING AT 300.
INITIAL CONDITIONS (PPM)

	NO2	NO	O3 .	HC1	HC2	HC3	CO	SOX
AMBIENT	0.020	0.020	0.030	0.132	0.330	0.0	0.0	0.0
OCS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

SOLAR	WSPD	HINV	STAB LEVEL	NO2	NO	HC1	HC2	HC3	CO	SOX
0.010	3.0	100.	40	0.	0.	0.	0.	0.	0.	
0.010	2.0	100.	40	0.	0.	0.	0.	0.	0.	
0.011	2.0	100.	40	0.	0.	0.	0.	0.	0.	
0.073	2.0	100.	40	0.	0.	0.	0.	0.	0.	
0.181	1.0	100.	40	0.	0.	0.	0.	0.	0.	
0.277	1.0	100.	40	0.	0.	0.	0.	0.	0.	
0.347	5.0	100.	40	0.	0.	0.	0.	0.	0.	
0.388	5.0	100.	40	0.	0.	0.	0.	0.	0.	
0.415	5.0	100.	40	0.	0.	0.	0.	0.	0.	
0.422	7.0	100.	40	0.	0.	0.	0.	0.	0.	
0.415	7.0	100.	40	0.	1.	0.	1.	0.	0.	
0.388	6.0	100.	40	0.	1.	0.	1.	0.	0.	

Figure C-18. RAPT INPUT DATA FOR NIPOMO, 1978 BASELINE

BLM OCS STUDY---SANTA MARIA TRAJECTORY JULY 30---1977 BASELINE 000000

YEAR= 1977 STARTING AT 0.

INITIAL CONDITIONS (PPM)

	NO2	NO	O3	HC1	HC2	HC3	CO	SOX
AMBIENT	0.050	0.030	0.030	0.132	0.330	0.0	0.300	0.0
OCS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

SOLAR	WSPD	HINV	STAB	LEVEL	NO2	NO	HC1	HC2	HC3	CO	SOX
0.010	1.0	20.	6		0.	0.	0.	0.	0.	0.	
0.010	1.0	20.	6		0.	0.	0.	0.	0.	0.	
0.010	1.0	20.	6		0.	0.	0.	0.	0.	0.	
0.010	1.0	20.	6		0.	0.	0.	0.	0.	0.	
0.010	1.0	20.	6		0.	0.	0.	0.	0.	0.	
0.010	1.0	20.	6		0.	0.	0.	0.	0.	0.	
0.044	3.0	20.	6		0.	0.	0.	0.	0.	0.	
0.043	3.0	20.	6		0.	0.	0.	0.	0.	0.	
0.139	7.0	20.	6		0.	0.	0.	0.	0.	0.	
0.233	7.0	20.	6		0.	0.	0.	0.	0.	0.	
0.290	9.0	125.	4		0.	0.	0.	0.	0.	0.	
0.324	8.0	175.	4		0.	2.	0.	1.	0.	0.	
0.337	8.0	175.	4		0.	2.	0.	1.	0.	0.	

Figure C-19. RAPT INPUT DATA FOR SANTA MARIA, 1977 BASELINE

RLM OCS STUDY---SANTA YNEZ TRAJECTORY JUNE 5---1977 BASELINE
YEAR= 1977 STARTING AT 2100.
INITIAL CONDITIONS (PPM)

	NO2	NO	O3	HC1	HC2	HC3	CO	SOX
AMBIENT	0.010	0.015	0.030	0.132	0.330	0.0	0.300	0.0
OCS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

SOLAR	WSPD	HINV	STAB	LEVEL	NO2	NO	HC1	HC2	HC3	CO	SOX
0.010	6.0	100.	4		0.	0.	0.	0.	0.	0.	
0.010	6.0	100.	4		0.	0.	0.	0.	0.	0.	
0.010	6.0	100.	4		0.	0.	0.	0.	0.	0.	
0.010	6.0	100.	4		0.	0.	0.	0.	0.	0.	
0.010	4.0	150.	4		0.	0.	0.	0.	0.	0.	
0.010	4.0	150.	4		0.	0.	0.	0.	0.	0.	
0.010	4.0	150.	4		0.	0.	0.	0.	0.	0.	
0.010	4.0	150.	4		0.	0.	0.	0.	0.	0.	
0.010	4.0	150.	4		0.	0.	0.	0.	0.	0.	
0.090	4.0	150.	4		0.	0.	0.	0.	0.	0.	
0.198	4.0	200.	4		0.	0.	0.	0.	0.	0.	
0.288	5.0	220.	4		0.	0.	0.	0.	0.	0.	
0.359	6.0	240.	4		0.	0.	0.	0.	0.	0.	
0.396	7.0	260.	4		0.	1.	0.	1.	0.	0.	
0.422	7.0	200.	4		0.	0.	0.	0.	0.	0.	
0.427	3.0	300.	4		0.	0.	0.	0.	0.	0.	
0.422	3.0	320.	4		0.	0.	0.	0.	0.	0.	

Figure C-20. RAPT INPUT DATA FOR SANTA YNEZ, 1977 BASELINE

BLM OCS STUDY---GOLETA TRAJECTORY JUNE 20---1976 BASELINE
YEAR= 1976 STARTING AT 1700.
INITIAL CONDITIONS (PPM)

	NO2	NO	O3	HC1	HC2	HC3	CO	SOX
AMBIENT	0.010	0.010	0.030	0.044	0.110	0.0	0.300	0.0
OCS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

SOLAR	WSPD	HINV	STAB LEVEL	NO2	NO	HC1	HC2	HC3	CO	SOX
0.051	6.0	480.	4	0.	0.	0.	0.	0.	0.	
0.036	6.0	480.	4	0.	0.	0.	0.	0.	0.	
0.010	6.0	480.	4	0.	0.	0.	0.	0.	0.	
0.010	6.0	480.	4	0.	0.	0.	0.	0.	0.	
0.010	6.0	480.	4	0.	0.	0.	0.	0.	0.	
0.010	6.0	480.	4	0.	0.	0.	0.	0.	0.	
0.010	6.0	480.	4	0.	0.	0.	0.	0.	0.	
0.010	6.0	480.	4	0.	0.	0.	0.	0.	0.	
0.010	4.0	480.	4	0.	0.	0.	0.	0.	0.	
0.010	4.0	480.	4	0.	0.	0.	0.	0.	0.	
0.010	4.0	480.	4	0.	0.	0.	0.	0.	0.	
0.010	4.0	480.	4	0.	0.	0.	0.	0.	0.	
0.010	4.0	480.	4	0.	0.	0.	0.	0.	0.	
0.037	7.0	480.	4	0.	0.	0.	0.	0.	0.	
0.051	6.0	480.	4	0.	0.	0.	0.	0.	0.	
0.150	6.0	480.	4	0.	0.	0.	0.	0.	0.	
0.246	6.0	480.	4	0.	0.	0.	0.	0.	0.	
0.299	5.0	480.	4	0.	0.	0.	0.	0.	0.	
0.335	8.0	480.	4	0.	0.	0.	0.	0.	0.	
0.348	8.0	480.	4	0.	0.	0.	0.	0.	0.	
0.335	5.0	480.	4	0.	1.	0.	1.	0.	0.	
0.300	8.0	480.	4	0.	0.	0.	0.	0.	0.	

Figure C-21. RAPT INPUT DATA FOR GOLETA, 1976 BASELINE

BLM OCS STUDY---BAY AREA TRAJECTORY 1- AUG 5---1990 BASELINE
YEAR= 1990 STARTING AT 0.
INITIAL CONDITIONS (PPM)

	NO2	NO	O3	HC1	HC2	HC3	CO	SOX
AMBIENT	0.009	0.009	0.019	0.032	0.079	0.0	0.0	0.0
OCS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

SOLAR	WSPD	HINV	STAR	LEVEL	NO2	NO	HC1	HC2	HC3	CO	SOX
0.010	5.0	100.	4		0.	0.	0.	0.	0.	0.	
0.010	6.0	110.	4		0.	0.	0.	0.	0.	0.	
0.010	8.0	110.	4		0.	0.	0.	0.	0.	0.	
0.010	8.0	120.	4		0.	0.	0.	0.	0.	0.	
0.010	7.0	120.	4		0.	0.	0.	0.	0.	0.	
0.012	4.0	120.	4		0.	0.	0.	0.	0.	0.	
0.097	4.0	120.	4		0.	0.	0.	0.	0.	0.	
0.202	3.0	130.	4		0.	0.	1.	2.	0.	35.	
0.288	6.0	80.	4		0.	3.	4.	13.	1.	44.	
0.356	4.0	100.	4		0.	1.	1.	3.	0.	7.	
0.393	6.0	150.	4		0.	5.	1.	5.	0.	16.	
0.420	6.0	180.	4		0.	0.	0.	0.	0.	0.	
0.424	5.0	200.	4		0.	0.	0.	0.	0.	1.	
0.420	6.0	500.	4		0.	0.	0.	0.	0.	0.	
0.393	5.0	600.	4		0.	0.	0.	0.	0.	0.	
0.356	9.0	600.	4		0.	0.	0.	0.	0.	0.	

Figure C-22. RAPT INPUT DATA FOR BAY AREA NO. 1, 1990 BASELINE

BLM OCS STUDY---BAY AREA TRAJECTORY 2-JULY 26--1990 BASELINE
YEAR= 1990 STARTING AT 400.
INITIAL CONDITIONS (PPM)

	NO2	NO	O3	HC1	HC2	HC3	CO	SOX
AMBIENT	0.018	0.009	0.019	0.085	0.211	0.0	0.0	0.0
OCS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

SOLAR	WSPD	HINV	STAB	LEVEL	NO2	NO	HC1	HC2	HC3	CO	SOX
0.010	6.0	120.	4		0.	0.	0.	0.	0.	0.	
0.010	8.0	200.	4		0.	0.	0.	0.	0.	0.	
0.010	6.0	240.	4		0.	0.	0.	0.	0.	0.	
0.036	4.0	120.	4		0.	0.	0.	0.	0.	1.	
0.127	6.0	60.	4		0.	0.	0.	1.	0.	5.	
0.217	4.0	30.	6		0.	1.	1.	2.	0.	11.	
0.277	3.0	60.	4		0.	1.	1.	3.	0.	8.	
0.309	12.0	100.	4		0.	1.	1.	3.	0.	11.	
0.320	9.0	150.	4		0.	2.	2.	9.	2.	18.	
0.309	10.0	150.	4		0.	0.	0.	0.	0.	0.	
0.277	13.0	200.	4		0.	0.	0.	0.	0.	1.	

Figure C-23. RAPT DATA INPUT FOR BAY AREA NO. 2, 1990 BASELINE

BLM OCS STUDY---BAY AREA TRAJECTORY 3-AUG 22---1987 BASELINE
YEAR= 1987 STARTING AT 100.
INITIAL CONDITIONS (PPM)

	NO2	NO	O3	HC1	HC2	HC3	CO	SOX
AMBIENT	0.009	0.009	0.022	0.032	0.079	0.0	0.0	0.0
OCS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

SOLAR	WSPD	HINV	STAB	LEVEL	NO2	NO	HC1	HC2	HC3	CO	SOX
0.010	4.0	100.	4		0.	0.	0.	0.	0.	0.	
0.010	4.0	90.	4		0.	0.	0.	0.	0.	0.	
0.010	4.0	80.	4		0.	0.	0.	0.	0.	0.	
0.010	4.0	80.	4		0.	0.	0.	0.	0.	0.	
0.021	6.0	70.	4		0.	0.	0.	0.	0.	0.	
0.061	11.0	60.	4		0.	0.	0.	0.	0.	0.	
0.164	8.0	50.	4		0.	0.	0.	0.	0.	0.	
0.264	6.0	100.	4		0.	0.	0.	0.	0.	0.	
0.329	6.0	200.	4		0.	0.	0.	0.	0.	2.	
0.377	4.0	300.	4		0.	1.	0.	1.	0.	6.	
0.400	4.0	400.	4		0.	0.	0.	0.	0.	1.	
0.409	12.0	600.	4		0.	0.	0.	0.	0.	0.	
0.400	6.0	800.	4		0.	0.	0.	0.	0.	1.	
0.377	7.0	800.	4		0.	0.	0.	0.	0.	0.	

Figure C-24. RAPT DATA INPUT FOR BAY AREA NO. 3, 1987 BASELINE

BLM OCS STUDY---BAY AREA TRAJECTORY 4-JULY 26---1987 BASELINE
YEAR= 1987 STARTING AT 200.
INITIAL CONDITIONS (PPM)

	NO2	NO	O3	HC1	HC2	HC3	CO	SOX
AMBIENT	0.009	0.009	0.021	0.092	0.231	0.0	0.0	0.0
OCS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

SOLAR	WSPD	HINV	STAB	LEVEL	NO2	NO	HC1	HC2	HC3	CO	SOX
0.010	14.0	50.	5		0.	0.	0.	0.	0.	0.	
0.010	13.0	60.	5		0.	0.	0.	0.	0.	0.	
0.010	12.0	70.	4		0.	0.	0.	0.	0.	0.	
0.010	9.0	80.	4		0.	0.	0.	0.	0.	0.	
0.034	6.0	90.	4		0.	0.	0.	0.	0.	0.	
0.123	6.0	100.	4		0.	0.	0.	0.	0.	0.	
0.211	6.0	120.	4		0.	0.	0.	0.	0.	2.	
0.272	3.0	120.	4		0.	6.	2.	7.	0.	4.	
0.303	5.0	120.	4		0.	0.	0.	1.	0.	4.	
0.314	7.0	150.	4		0.	0.	0.	0.	0.	0.	
0.303	9.0	200.	4		0.	1.	0.	1.	0.	3.	
0.272	17.0	400.	4		0.	0.	0.	0.	0.	1.	

Figure C-25. RAPT DATA INPUT FOR BAY AREA NO. 4, 1987 BASELINE

BLM OCS STUDY---BAY AREA TRAJECTORY 5- SEPT 9---1987 BASELINE
YEAR= 1987 STARTING AT 100.
INITIAL CONDITIONS (PPM)

	NO2	NO	O3	HC1	HC2	HC3	CO	SOX
AMBIENT	0.075	0.028	0.023	0.330	0.825	0.0	0.0	0.0
OCS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

SOLAR	WSPD	HINV	STAB	LEVEL	NO2	NO	HC1	HC2	HC3	CO	SOX
0.010	3.0	50.	5		0.	0.	0.	0.	0.	0.	
0.010	3.0	60.	5		0.	0.	0.	0.	0.	0.	
0.010	3.0	70.	4		0.	0.	0.	0.	0.	0.	
0.010	2.0	80.	4		0.	0.	0.	0.	0.	0.	
0.010	5.0	90.	4		0.	0.	0.	0.	0.	0.	
0.010	4.0	100.	4		0.	0.	0.	0.	0.	0.	
0.010	4.0	110.	4		0.	0.	0.	0.	0.	0.	
0.073	5.0	120.	4		0.	0.	0.	0.	0.	0.	
0.156	3.0	120.	4		0.	0.	0.	0.	0.	0.	
0.222	5.0	120.	4		0.	0.	0.	0.	0.	0.	
0.261	7.0	200.	4		0.	0.	0.	0.	0.	0.	
0.271	10.0	250.	4		0.	0.	0.	0.	0.	2.	
0.261	10.0	400.	4		0.	0.	0.	0.	0.	0.	
0.222	9.0	500.	4		0.	0.	0.	0.	0.	0.	
0.155	7.0	700.	4		0.	0.	0.	0.	0.	0.	
0.073	9.0	900.	4		0.	0.	0.	0.	0.	1.	
0.010	11.0	1000.	4		0.	0.	0.	0.	0.	4.	

Figure C-26. RAPT INPUT DATA FOR BAY AREA NO. 5, 1987 BASELINE

BLM OCS STUDY---BAY AREA TRAJECTORY 6- AUG 5---1990 BASELINE
YEAR= 1990 STARTING AT 0.
INITIAL CONDITIONS (PPM)

	NO2	NO	O3	HC1	HC2	HC3	CO	SOX
AMBIENT	0.009	0.009	0.022	0.317	0.792	0.0	0.0	0.0
OCS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

SOLAR	WSPD	HINV	STAB LEVEL	NO2	NO	HC1	HC2	HC3	CO	SOX
0.010	5.0	100.	4	0.	0.	0.	0.	0.	0.	
0.010	10.0	110.	4	0.	0.	0.	0.	0.	0.	
0.010	7.0	110.	4	0.	0.	0.	0.	0.	0.	
0.010	8.0	120.	4	0.	0.	0.	0.	0.	0.	
0.010	7.0	120.	4	0.	0.	0.	0.	0.	0.	
0.012	4.0	120.	4	0.	0.	0.	0.	0.	5.	
0.097	3.0	100.	4	0.	8.	1.	2.	1.	25.	
0.202	4.0	80.	4	0.	2.	1.	3.	0.	32.	
0.288	5.0	120.	4	0.	0.	0.	0.	0.	1.	
0.356	6.0	120.	4	0.	0.	0.	0.	0.	1.	
0.393	4.0	120.	4	0.	0.	0.	0.	0.	0.	
0.420	5.0	200.	4	0.	0.	0.	1.	0.	1.	
0.424	7.0	300.	4	0.	1.	1.	3.	0.	5.	
0.420	6.0	400.	4	0.	1.	1.	4.	0.	12.	
0.393	5.0	500.	4	0.	2.	2.	5.	0.	23.	
0.356	4.0	600.	4	0.	1.	1.	2.	0.	17.	
0.288	4.0	300.	4	0.	0.	0.	0.	0.	2.	

Figure C-27. RAPT INPUT DATA FOR BAY AREA NO. 6, 1990 BASELINE

BLM OCS STUDY---BAY AREA TRAJECTORY 7 - SEPT 9---1987 BASELINE
YEAR= 1987 STARTING AT 100.
INITIAL CONDITIONS (PPM)

	NO2	NO	O3	HC1	HC2	HC3	CO	SOX
AMBIENT	0.009	0.028	0.023	0.099	0.248	0.0	0.0	0.0
OCS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

SOLAR	WSPD	HINV	STAB	LEVEL	NO2	NO	HC1	HC2	HC3	CO	SOX
0.010	4.0	70.	4		0.	0.	0.	0.	0.	0.	
0.010	5.0	80.	4		0.	0.	0.	0.	0.	0.	
0.010	4.0	80.	4		0.	0.	0.	0.	0.	0.	
0.010	4.0	90.	4		0.	0.	0.	0.	0.	0.	
0.010	5.0	100.	4		0.	0.	0.	0.	0.	0.	
0.010	5.0	110.	4		0.	0.	0.	0.	0.	0.	
0.010	6.0	120.	4		0.	0.	0.	0.	0.	0.	
0.078	6.0	120.	4		0.	0.	0.	0.	0.	0.	
0.162	14.0	120.	4		0.	0.	0.	0.	0.	0.	
0.230	10.0	120.	4		0.	0.	0.	0.	0.	0.	
0.266	7.0	150.	4		0.	0.	0.	0.	0.	0.	
0.277	7.0	200.	4		0.	0.	0.	0.	0.	0.	
0.266	5.0	400.	4		0.	0.	0.	1.	0.	5.	
0.230	8.0	300.	4		0.	0.	0.	1.	0.	4.	
0.162	7.0	600.	4		0.	1.	0.	1.	0.	6.	
0.078	7.0	800.	4		0.	0.	0.	0.	0.	2.	

Figure C-28. RAPT INPUT DATA FOR BAY AREA NO. 7, 1987 BASELINE

BLM OCS STUDY---SCOTTS VALLEY TRAJECTOEY SEPT 9---1987 BASELINE
YEAR= 1990 STARTING AT 300.
INITIAL CONDITIONS (PPM)

	NO2	NO	O3	HC1	HC2	HC3	CO	SOX
AMBIENT	0.113	0.065	0.008	0.541	1.350	0.0	0.0	0.0
OCS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

SOLAR	WSPD	HINV	STAB	LEVEL	NO2	NO	HC1	HC2	HC3	CO	SOX
0.010	10.0	80.	4		0.	0.	0.	0.	0.	0.	
0.010	7.0	80.	4		0.	0.	0.	0.	0.	0.	
0.010	10.0	100.	4		0.	0.	0.	0.	0.	0.	
0.010	5.0	110.	4		0.	0.	0.	0.	0.	0.	
0.010	6.0	120.	4		0.	0.	0.	0.	0.	0.	
0.078	4.0	120.	4		0.	0.	0.	0.	0.	0.	
0.162	7.0	120.	4		0.	0.	0.	0.	0.	0.	
0.230	6.0	150.	4		0.	0.	0.	0.	0.	0.	
0.266	8.0	200.	4		0.	0.	0.	0.	0.	0.	
0.277	6.0	300.	4		0.	0.	0.	0.	0.	0.	
0.266	7.0	500.	4		0.	0.	0.	0.	0.	0.	
0.230	8.0	500.	4		0.	0.	0.	0.	0.	0.	
0.162	5.0	600.	4		0.	0.	0.	0.	0.	0.	
0.078	5.0	400.	4		0.	0.	0.	0.	0.	0.	
0.010	4.0	200.	4		0.	0.	0.	1.	0.	0.	

Figure C-29. RAPT INPUT DATA FOR SCOTTS VALLEY, 1987 BASELINE

BLM OCS STUDY---SALINAS TRAJECTORY AUG 5---1990 BASELINE
YEAR= 1990 STARTING AT 300.
INITIAL CONDITIONS (PPM)

	NO2	NO	O3	HC1	HC2	HC3	CO	SOX
AMBIENT	0.002	0.012	0.025	0.007	0.090	0.0	0.180	0.0
OCS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

SOLAR	WSPD	HINV	STAB	LEVEL	NO2	NO	HC1	HC2	HC3	CO	SOX
0.010	17.0	100.	4		0.	0.	0.	0.	0.	0.	
0.010	20.0	100.	4		0.	0.	0.	0.	0.	0.	
0.012	16.0	100.	4		0.	0.	0.	0.	0.	0.	
0.097	17.0	100.	4		0.	0.	0.	0.	0.	0.	
0.202	19.0	100.	4		0.	0.	0.	0.	0.	0.	
0.288	18.0	100.	4		0.	0.	0.	0.	0.	0.	
0.356	20.0	100.	4		0.	0.	0.	0.	0.	0.	
0.393	18.0	0.	40		0.	0.	0.	1.	0.	0.	

Figure C-30. RAPT INPUT DATA FOR SALINAS, 1990 BASELINE

BLM OCS STUDY---MONTEREY TRAJECTORY AUG 5---1990 BASELINE
YEAR= 1990 STARTING AT 300.
INITIAL CONDITIONS (PPM)

	NO2	NO	O3	HC1	HC2	HC3	CO	SOX
AMBIENT	0.008	0.012	0.025	0.007	0.018	0.0	0.180	0.0
OCS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

SOLAR	WSPD	HINV	STAB	LEVEL	NO2	NO	HC1	HC2	HC3	CO	SOX
0.010	17.0	100.	4		0.	0.	0.	0.	0.	0.	
0.010	20.0	100.	4		0.	0.	0.	0.	0.	0.	
0.012	16.0	100.	4		0.	0.	0.	0.	0.	0.	
0.097	17.0	100.	4		0.	0.	0.	0.	0.	0.	
0.202	19.0	100.	4		0.	0.	0.	0.	0.	0.	
0.288	18.0	100.	4		0.	0.	0.	0.	0.	0.	
0.356	20.0	100.	4		0.	0.	0.	0.	0.	0.	
0.393	1.0	0.	0		0.	0.	0.	1.	0.	0.	

Figure C-31. RAPT INPUT DATA FOR MONTEREY, 1990 BASELINE

BLM OCS STUDY---NIPOMO TRAJECTORY SEPT 29---1991 BASELINE
YEAR= 1991 STARTING AT 300.
INITIAL CONDITIONS (PPM)

	NO2	NO	O3	HC1	HC2	HC3	CO	SOX
AMBIENT	0.033	0.033	0.037	0.162	0.410	0.0	0.0	0.0
OCS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

SOLAR	WSPD	HINV	STAB	LEVEL	NO2	NO	HC1	HC2	HC3	CO	SOX
0.010	3.0	100.	40		0.	0.	0.	0.	0.	0.	
0.010	2.0	100.	40		0.	0.	0.	0.	0.	0.	
0.011	2.0	100.	40		0.	0.	0.	0.	0.	0.	
0.073	2.0	100.	40		0.	0.	0.	0.	0.	0.	
0.181	1.0	100.	40		0.	0.	0.	0.	0.	0.	
0.277	1.0	100.	40		0.	0.	0.	0.	0.	0.	
0.347	5.0	100.	40		0.	0.	0.	0.	0.	0.	
0.388	5.0	100.	40		0.	0.	0.	0.	0.	0.	
0.415	5.0	100.	40		0.	0.	0.	0.	0.	0.	
0.422	7.0	100.	40		0.	0.	0.	0.	0.	0.	
0.415	7.0	100.	40		0.	1.	0.	1.	0.	0.	
0.388	6.0	100.	40		0.	1.	0.	1.	0.	0.	

Figure C-32. RAPT INPUT DATA FOR NIPOMO, 1991 BASELINE

BLM OCS STUDY---SANTA MARIA TRAJECTORY JULY 30---1991 BASELINE 000000

YEAR= 1991 STARTING AT 0.

INITIAL CONDITIONS (PPM)

	NO2	NO	O3	HC1	HC2	HC3	CO	SOX
AMBIENT	0.038	0.023	0.017	0.074	0.185	0.0	0.153	0.0
OCS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

SOLAR	WSPD	HINV	STAB	LEVEL	NO2	NO	HC1	HC2	HC3	CO	SOX
0.010	1.0	20.	6		0.	0.	0.	0.	0.	0.	
0.010	1.0	20.	6		0.	0.	0.	0.	0.	0.	
0.010	1.0	20.	6		0.	0.	0.	0.	0.	0.	
0.010	1.0	20.	6		0.	0.	0.	0.	0.	0.	
0.010	1.0	20.	6		0.	0.	0.	0.	0.	0.	
0.010	1.0	20.	6		0.	0.	0.	0.	0.	0.	
0.044	3.0	20.	6		0.	0.	0.	0.	0.	0.	
0.043	3.0	20.	6		0.	0.	0.	0.	0.	0.	
0.139	7.0	20.	6		0.	0.	0.	0.	0.	0.	
0.233	7.0	20.	6		0.	0.	0.	0.	0.	0.	
0.290	9.0	125.	4		0.	0.	0.	0.	0.	0.	
0.324	8.0	175.	4		0.	1.	0.	1.	0.	0.	
0.337	8.0	175.	4		0.	0.	0.	0.	0.	0.	

Figure C-33. RAPT INPUT DATA FOR SANTA MARIA, 1991 BASELINE

BLM OCS STUDY---SANTA YNEZ TRAJECTORY JUNE 5---1991 BASELINE
YEAR= 1991 STARTING AT 2100.
INITIAL CONDITIONS (PPM)

	NO2	NO	O3	HC1	HC2	HC3	CO	SOX
AMBIENT	0.008	0.012	0.018	0.078	0.195	0.0	0.165	0.0
OCS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

SOLAR	WSPD	HINV	STAB	LEVEL	NO2	NO	HC1	HC2	HC3	CO	SOX
0.010	6.0	100.	4		0.	0.	0.	0.	0.	0.	
0.010	6.0	100.	4		0.	0.	0.	0.	0.	0.	
0.010	6.0	100.	4		0.	0.	0.	0.	0.	0.	
0.010	6.0	100.	4		0.	0.	0.	0.	0.	0.	
0.010	4.0	150.	4		0.	0.	0.	0.	0.	0.	
0.010	4.0	150.	4		0.	0.	0.	0.	0.	0.	
0.010	4.0	150.	4		0.	0.	0.	0.	0.	0.	
0.010	4.0	150.	4		0.	0.	0.	0.	0.	0.	
0.010	4.0	150.	4		0.	0.	0.	0.	0.	0.	
0.090	4.0	150.	4		0.	0.	0.	0.	0.	0.	
0.198	4.0	200.	4		0.	0.	0.	0.	0.	0.	
0.288	5.0	220.	4		0.	0.	0.	0.	0.	0.	
0.359	6.0	240.	4		0.	0.	0.	0.	0.	0.	
0.396	7.0	260.	4		0.	1.	0.	1.	0.	0.	
0.422	7.0	200.	4		0.	0.	0.	0.	0.	0.	
0.427	3.0	300.	4		0.	0.	0.	0.	0.	0.	
0.422	3.0	320.	4		0.	0.	0.	0.	0.	0.	

Figure C-34. RAPT INPUT DATA FOR SANTA YNEZ, 1991 BASELINE

BLM OCS STUDY---GOLETA TRAJECTORY JUNE 20---1991 BASELINE
YEAR= 1991 STARTING AT 1700.
INITIAL CONDITIONS (PPM)

	NO2	NO	O3	HC1	HC2	HC3	CO	SOX
AMBIENT	0.008	0.008	0.018	0.026	0.066	0.0	0.141	0.0
OCS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

SOLAR	WSPD	HINV	STAB	LEVEL	NO2	NO	HC1	HC2	HC3	CO	SOX
0.051	6.0	480.	4		0.	0.	0.	0.	0.	0.	
0.036	6.0	480.	4		0.	0.	0.	0.	0.	0.	
0.010	6.0	480.	4		0.	0.	0.	0.	0.	0.	
0.010	6.0	480.	4		0.	0.	0.	0.	0.	0.	
0.010	6.0	480.	4		0.	0.	0.	0.	0.	0.	
0.010	6.0	480.	4		0.	0.	0.	0.	0.	0.	
0.010	6.0	480.	4		0.	0.	0.	0.	0.	0.	
0.010	6.0	480.	4		0.	0.	0.	0.	0.	0.	
0.010	4.0	480.	4		0.	0.	0.	0.	0.	0.	
0.010	4.0	480.	4		0.	0.	0.	0.	0.	0.	
0.010	4.0	480.	4		0.	0.	0.	0.	0.	0.	
0.010	4.0	480.	4		0.	0.	0.	0.	0.	0.	
0.010	4.0	480.	4		0.	0.	0.	0.	0.	0.	
0.037	7.0	480.	4		0.	0.	0.	0.	0.	0.	
0.051	6.0	480.	4		0.	0.	0.	0.	0.	0.	
0.150	6.0	480.	4		0.	0.	0.	0.	0.	0.	
0.246	6.0	480.	4		0.	0.	0.	0.	0.	0.	
0.299	5.0	480.	4		4.	0.	4.	0.	5.	********	
0.335	8.0	480.	4		0.	0.	0.	0.	0.	0.	
0.348	8.0	480.	4		0.	0.	0.	0.	0.	0.	
0.335	5.0	480.	4		0.	0.	0.	0.	0.	0.	
0.300	8.0	480.	4		0.	0.	0.	0.	0.	0.	

Figure C-35. RAPT INPUT DATA FOR GOLETA, 1991 BASELINE

Tables C-38 through C-42 describe emissions for photochemical modeling of potential Lease Sale No. 53 emissions using the RAPT model (described principally in Appendix B, with additional clarifications in Section C of Chapter VI). The first table (C-38) has a key which describes the abbreviations used in the tables. Emissions scenarios and simulation cases are described in Chapters V and VI, respectively. The emissions were directly prepared using Tables C-1, C-6, C-11, C-16 and C-21. A complete description also requires examination of trajectory figures in Chapter IV. A systematic study of photochemical modeling which will give meaning to these tables should begin with Section IV-A-4 (meteorology and trajectories) and continue with Section VI-C (photochemical modeling).

Table C-38. RAPT SCENARIO EMISSIONS FOR EEL RIVER ZONE

Trajectory : Eureka

Case:	1	1A1	1A2	1A3
Emissions Scenario:	1-3			
Time (PST):				
0500	62./6.9/13./23.5 C	+0/950/9/0 C	+0/9500/0/0 C	
0600	21./0.7/0.4/1.0 C			+0/9500/9/0C
0700	13.1/212./14./49.5 C			

Key: See Text Section VI.C.7 for case definition.

Scenarios are defined in Section V.D.2.

"C" designates emissions along trajectory centerline.

"+" designates emissions added to base case.

Emissions are given in the order NO_x (as NO_2) /RHC/CO/SO_2 in units of lbs/hr.

Additional Assumptions:

Gas is assumed 35% reactive in the lumped form HC2 (mostly alkanes) in the LIRAQ chemistry.

Oil is assumed 95% reactive (as RHC) with 90% of RHC in the lumped form HC2 and 10% as HCl (alkenes, etc.).

Table C-39. RAPT SCENARIO EMISSIONS FOR POINT ARENA ZONE

Trajectory : Fort Bragg

Case:	1	1A2	1A4
Emissions Scenario:	1 and 2		
Time (PST):			
0000	55./1.1/8.3/3.8 C		
0100	184./184./29.3/163. C	+0/4400./0/0 C	
0200	63/1.4/9.8/126. C		
0300	223./801./35.3/31.8 C		
0400			
0500	21./16.4/5.7/16. C		
0600			
0700	26./17.4/5.7/16. C		+0/4400/0/0 C

Key: (see Eel River Emissions)

Table C-40. RAPT SCENARIO EMISSIONS FOR BODEGA BAY ZONE

Trajectory : Bay Area #3

Case:	1	1A1	1A3
Emissions Scenario:	1, 1A & 2		
Time (PST):			
0200	19.5/587./2.4/2 C	+0/314,160./0/0 C	
0300			
0400	60.5/7.3/7.5/12.1		+0/4400/0/0 C
0500	56.5/1.4/7./5.5 C		
0600			

Trajectory : Bay Area #4

Case:	1	1A1
Emissions Scenario:	1, 1A & 2	
Time (PST):		
0200	60.5/7.3/7.5/12.1 C	+44./628./0./0. C
0300	104./589./12.9/9.8 C	

Trajectory : Bay Area #5

Case:	1
Emissions Scenario:	1, 1A & 2
Time (PST):	
0400	60.5/7.3/7.5/12.1 C
0500	84.5/2.1/10.5/7.8 C
0600	19.5/587./2.4/2. C

Table C-40 (Continued) RAPT SCENARIO EMISSIONS FOR BODEGA BAY ZONE

Trajectory : Bay Area #7

Case:	1
Emissions Scenario:	1, 1A & 2
Time (PST):	
0100	60.5/7.3/7.5/12.1 C
0200	84.5/2.1/10.5/7.8 C
0300	19.5/587./2.4/2. C

Key: (see Eel River Emissions)

Table C-41. RAPT SCENARIO EMISSIONS FOR SANTA CRUZ ZONE

Trajectory : Bay Area #1

Case:	1	2	2A1	2A2
Emissions Scenario:	1	2	2	2
Time (PST):				
0300	79./10.3/10.6/13.C	79./10.8/10.3/13C	+0/4400./0/0C	
0400	114./81./15.3/26.1C	157./182.2/21./27.6C		+0/314.160/0/0C
0500	0/11.4/0/0	0/6./0/0		

Trajectory : Bay Area #2

Case:	1
Emissions Scenario:	1
Time (PST):	
0400	21.3/8.8/2.9/6.8C
0500	86./87./11.5/20.5C
0600	163./1.2/8.4/4.C

Trajectory : Bay Area #6

Case:	1
Emissions Scenario:	3
Time (PST):	
0000	10./18.1/1.3/6.
0100	110.5/10.9/14.6/15.C
0200	45./826.4/6./397.6C

Table C-41. (Continued) RAPT SCENARIO EMISSIONS FOR SANTA CRUZ ZONE

Trajectory : Scott's Valley

Case:	1	
Emissions Scenario:	1	
Time (PST):		
0300	97.6/77.8/13.1/21.3 C	
0400	16./9./2.1/9.	
0500		
0600		
0700	76./69./10.2/14.5	
	79./10.3/10.4/9.8 C	
0800	10./18.1/1.3/6 C	

Trajectory : Salinas/Monterey

Case:	1		
Emissions Scenario:	1		2A1
Time (PST):			
0500	42.6/17.6/5.8/13.6 C		
	16./9./2.1/9.		
0600	86./87./11.5/20.5 C	+37./1653./4.9/3. C	
	16./9./2.1/9.		

Table C-42. RAPT SCENARIO EMISSIONS FOR SANTA MARIA ZONE

Trajectory : Nipomo

Case:	1	1A2
Emissions Scenario:	1	
Time (PST):		
0400	22.5/10.7/12.7.5	
0500		
0600	77./11.7/13./11.3 C	+0/4400./0/0. C
0700		
0800		
0900	33./131./3.3/39. C	
1000	12.8/12.2/12./14.3	

Trajectory : Santa Maria

Case:	
Emissions Scenario:	1
Time (PST):	
0100	22.5/10.7/5./7.5 C
0200	
0300	77./11.7/13./11.3
0400	
0500	77./11.7/13/11.3 C
0600	33./131./12./39 C
0700	
0800	22.5/10.7/5./7.5

Table C-42. (Continued) RAPT SCENARIO EMISSIONS FOR SANTA MARIA ZONE

Trajectory : Santa Ynez

Case:	1	1A1	1A2	1A3
Emissions Scenario: 1				
Time (PST):				
2100	77./11.7/13./11.3			
2200				
2300	77./11.7/13./11.3			
0000	33./131./3.3/39. C			
0000	22.5/10.7/12./7.5 C	0/314/60./0/0 C	0/4400./0/0 C	
0200	20.2/200./2./3.8 C 0/14.3/0/0			44./628./5./10. C
0300				
0400	77./11.7/13./11.3			
0500	14./10.5/13./7.			
0600	83./12.2/12./14.3			

Table C-42. (Continued) RAPT SCENARIO EMISSIONS FOR SANTA MARIA ZONE

Trajectory : Goleta

Case:	1	1A1	1A2
Emissions Scenario: 1			
Time (PST):			
1700	77./11.7/13./11.3		
1900	77/11.7/13./11.3		
	33./131./3.3/39.C		
2000	22.5/10.7/12./7.5 C	+0/314160./0/0 C	
2200	20.2/200./2./38. C 0/14.3/0/0		
2300	22.5/10.7/5./7.5 C		
0000	14./10.5/13./7. C		
0100	83./12.2/12./14.3 C		
0200	55.5/23.8/15.3/46.5 C		
0500	77./11.7/13./11.3		+0/4400/0/0 C

References.

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Woodward-Clyde Consultants, et al. 1979. Draft Environmental Impact Report/EA for the Proposed Wickland Oil Company Petroleum Products Facility at Selby, California. Volumes I and II. Prepared for the State of California Lands Commission.

APPENDIX D

MODELING RESULTS

APPENDIX D. MODELING RESULTS

This appendix contains figures describing photochemical modeling results which are not displayed in Section C of Chapter VI. Figures D-1 through D-29 represent the time evolution of nitrogen dioxide (NO_2) and ozone (O_3) concentrations for current year and future year baseline simulations.

Plots are given in pairs, one for NO_2 and one for O_3. Time is displayed along the horizontal axis, as given in the trajectories which are described in Section A.4 of Chapter IV. The current year (or calibration) baseline is dotted, and the future year (or modeling assessment) baseline is solid. The latter also appears in the time-evolution figures for modeling cases in Section VI.C. Trajectories for Eel River and Point Arena are not displayed here since the hypothetical baselines for these zones are assumed to be identical in the current and future years. Where available, observed NO_2 and O_3 measurements are superimposed on the plots. A summary of measured versus simulated ozone values is plotted as Figure VI-8. The computer inputs which were used to generate the baselines are presented in Figures C-5 through C-35, in Appendix C.

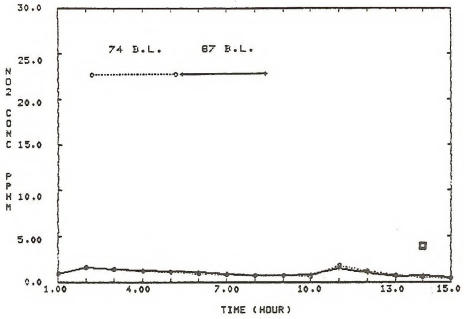

Figure D-1. NO_2 BASELINE SIMULATIONS FOR THE BAY AREA #3 TRAJECTORY

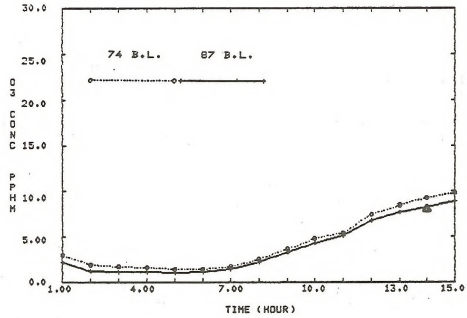

Figure D-2. O_3 BASELINE SIMULATIONS FOR THE BAY AREA #3 TRAJECTORY

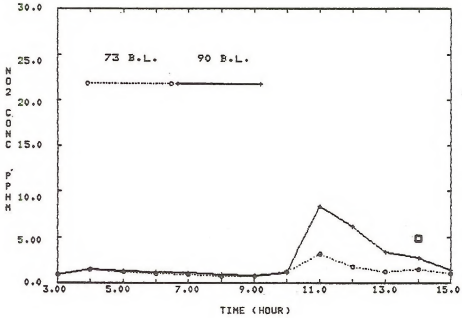

Figure D-3 NO_2 BASELINE SIMULATIONS FOR THE BAY AREA #4 TRAJECTORY

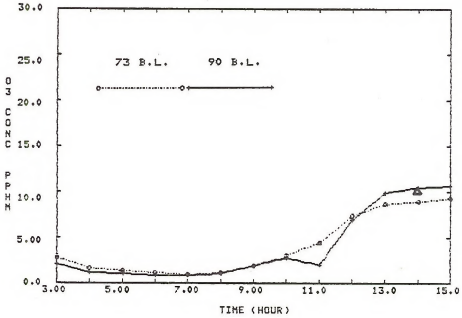

Figure D-4. O_3 BASELINE SIMULATIONS FOR THE BAY AREA #4 TRAJECTORY

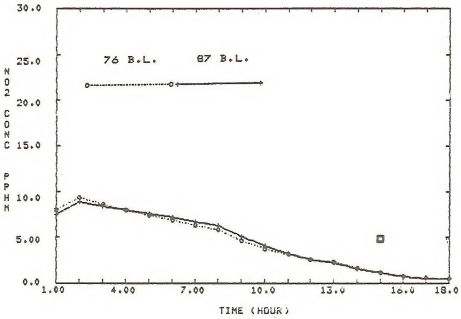

Figure D-5. NO_2 BASELINE SIMULATIONS FOR THE BAY AREA #5 TRAJECTORY

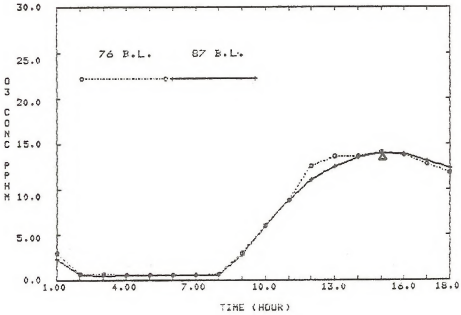

Figure D-6. O_3 BASELINE SIMULATIONS FOR THE BAY AREA #5 TRAJECTORY

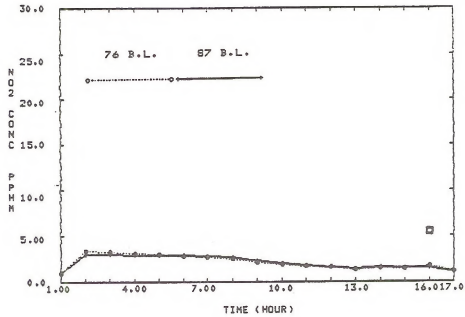

Figure D-7. NO_2 BASELINE SIMULATIONS FOR THE BAY AREA #7 TRAJECTORY

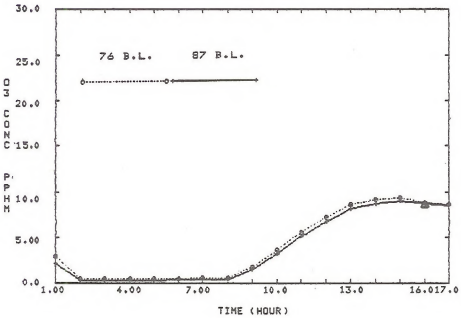

Figure D-8. O_3 BASELINE SIMULATIONS FOR THE BAY AREA #7 TRAJECTORY

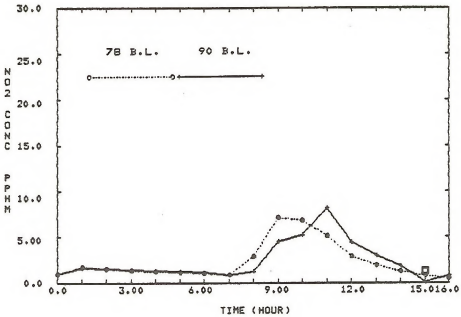

Figure D-9. NO_2 BASELINE SIMULATIONS FOR THE BAY AREA #1 TRAJECTORY

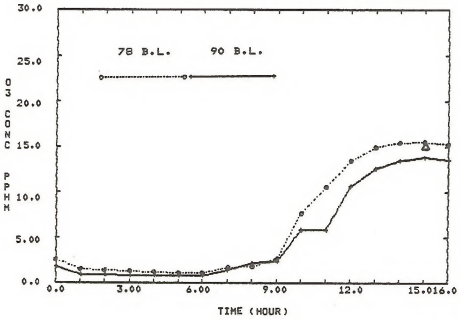

Figure D-10. O_3 BASELINE SIMULATIONS FOR THE BAY AREA #1 TRAJECTORY

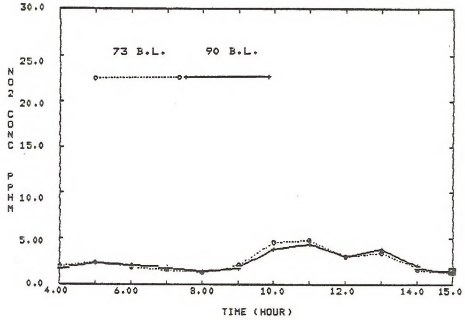

Figure D-11. NO_2 BASELINE SIMULATIONS FOR THE BAY AREA #2 TRAJECTORY

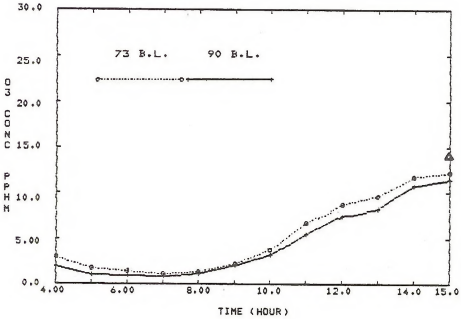

Figure D-12. O_3 BASELINE SIMULATIONS FOR THE BAY AREA #2 TRAJECTORY

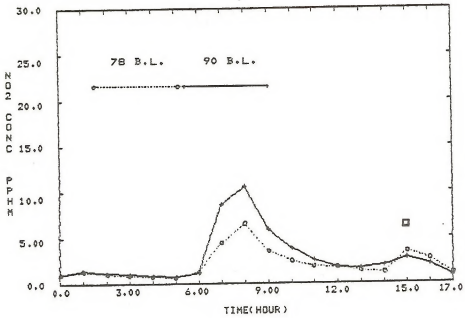

Figure D-13. NO_2 BASELINE SIMULATIONS FOR THE BAY AREA #6 TRAJECTORY

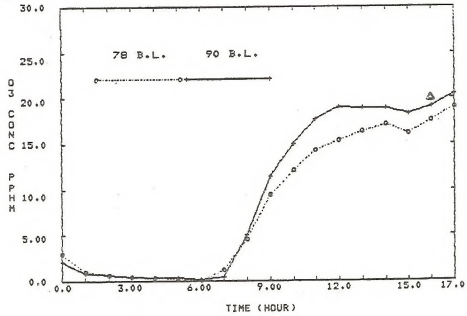

Figure D-14. O_3 BASELINE SIMULATIONS FOR THE BAY AREA #6 TRAJECTORY

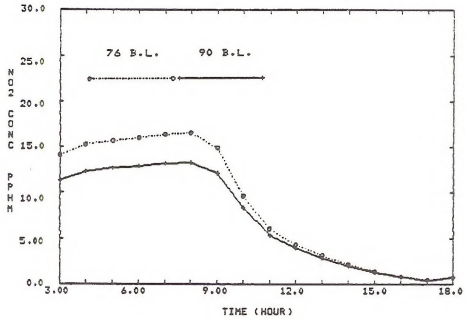

Figure D-15. NO_2 BASELINE SIMULATIONS FOR THE SCOTTS VALLEY TRAJECTORY

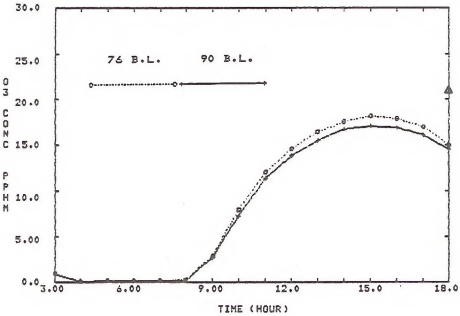

Figure D-16. O_3 BASELINE SIMULATIONS FOR THE SCOTTS VALLEY TRAJECTORY

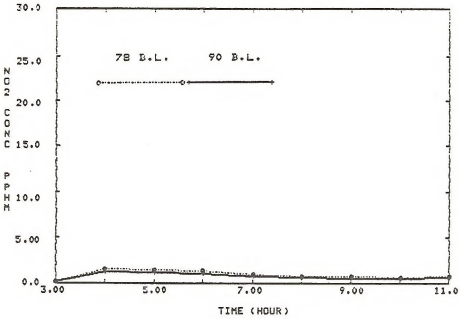

Figure D-17. NO_2 BASELINE SIMULATIONS FOR THE SALINAS TRAJECTORY

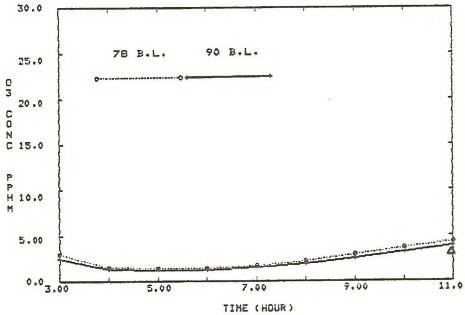

Figure D-18. O_3 BASELINE SIMULATIONS FOR THE SALINAS TRAJECTORY

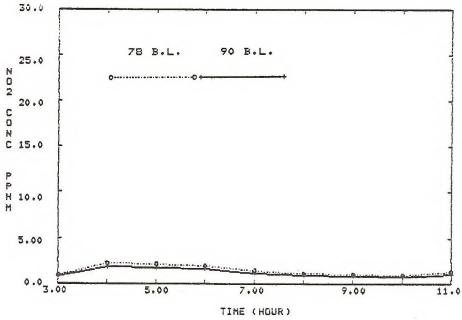

Figure D-19. NO_2 BASELINE SIMULATIONS FOR THE MONTEREY TRAJECTORY

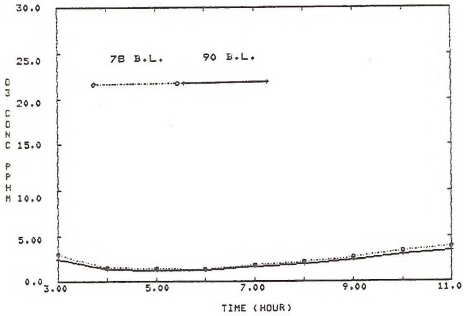

Figure D-20. O_3 BASELINE SIMULATIONS FOR THE MONTEREY TRAJECTORY

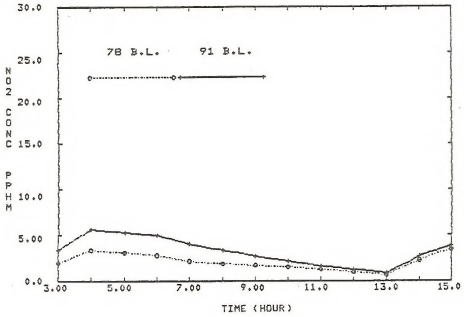

Figure D-21. NO_2 BASELINE SIMULATIONS FOR THE NIPOMO TRAJECTORY

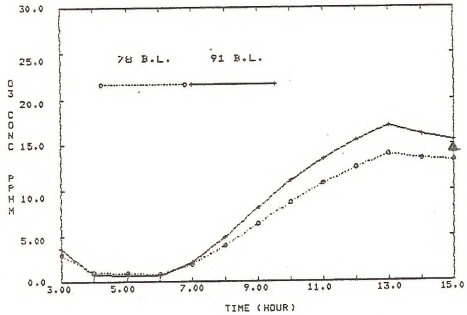

Figure D-22. O_3 BASELINE SIMULATIONS FOR THE NIPOMO TRAJECTORY

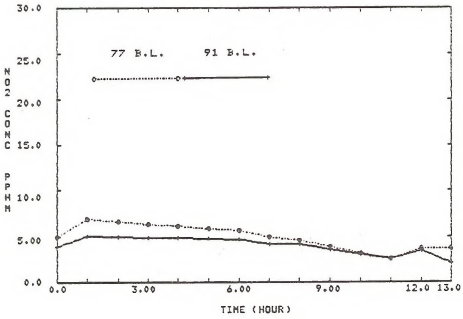

Figure D-23. NO_2 BASELINE SIMULATIONS FOR THE SANTA MARIA TRAJECTORY

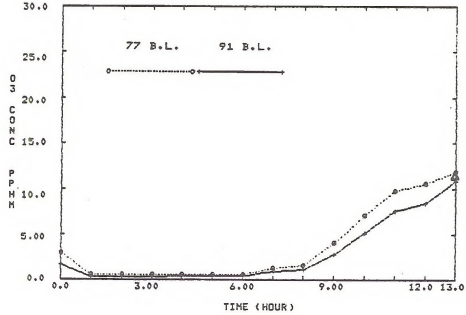

Figure D-24. O_3 BASELINE SIMULATIONS FOR THE SANTA MARIA TRAJECTORY

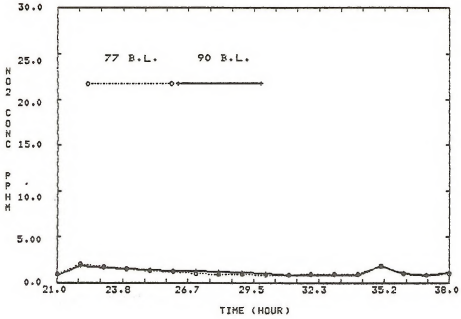

Figure D-25. NO_2 BASELINE SIMULATIONS FOR THE SANTA YNEZ TRAJECTORY

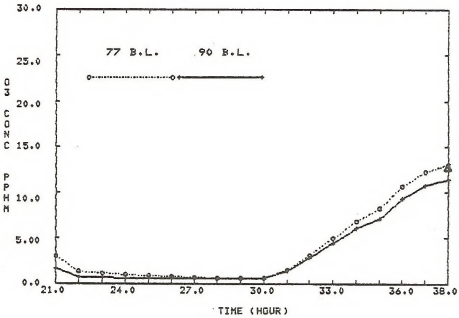

Figure D-26. O_3 BASELINE SIMULATIONS FOR THE SANTA YNEZ TRAJECTORY

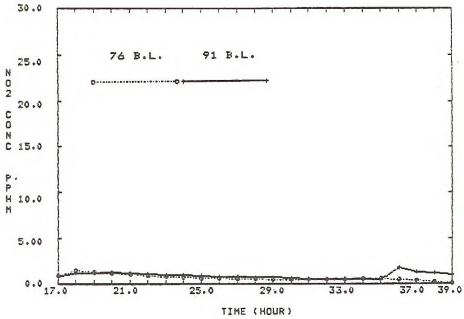

Figure D-27. NO_2 BASELINE SIMULATIONS FOR THE GOLETA TRAJECTORY

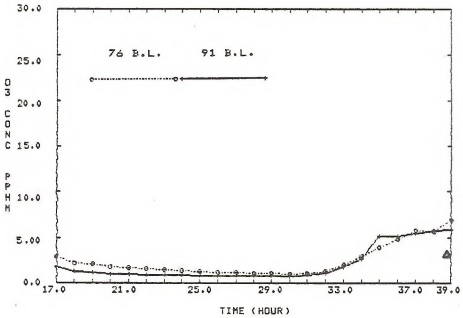

Figure D-28. O_3 BASELINE SIMULATIONS FOR THE GOLETA TRAJECTORY

Figure D-29 displays a typical segment of computer output from the RAPT photochemical model. The segment describes NO_2 concentrations during the 1200 PST hour of a simulation (not from this study). Such output results from adding study emissions (as summarized in Tables C-38 through C-42) to the corresponding future year baseline.

VERTICAL DIRECTION: CELL CONCENTRATIONS

SAN DIEGO OCS---7/8/76---1988 CASE A1 ← RUN TITLE (TRAJECTORY, DATE, CASE)

SPECIES ← HO2 CONCENTRATIONS (PPM) AT TIME = 1200.000 ← SIMULATION HOUR

										CONCENTRATION (ppm)	
K = 10	0.119E-05	0.119E-05	0.109E-05	0.872E-06	0.556E-06	0.222E-06	0.421E-07	0.516E-08		0.218E-08	0.209E-08
K = 9	0.292E-05	0.289E-05	0.231E-05	0.139E-05	0.724E-06	0.259E-06	0.451E-07	0.527E-08		0.229E-08	0.220E-08
K = 8	0.188E-04	0.184E-04	0.120E-04	0.398E-05	0.119E-05	0.336E-06	0.523E-07	0.585E-08		0.267E-08	0.258E-08
K = 7	0.122E-03	0.120E-03	0.723E-04	0.160E-04	0.240E-05	0.474E-06	0.668E-07	0.726E-08		0.337E-08	0.328E-08
K = 6	0.149E-03	0.148E-03	0.960E-04	0.245E-04	0.340E-05	0.548E-06	0.739E-07	0.787E-08		0.353E-08	0.342E-08
K = 5	0.171E-03	0.170E-03	0.111E-03	0.278E-04	0.366E-05	0.566E-06	0.756E-07	0.803E-08		0.361E-08	0.349E-08
K = 4	0.191E-03	0.189E-03	0.123E-03	0.304E-04	0.381E-05	0.575E-06	0.765E-07	0.812E-08		0.366E-08	0.354E-08
K = 3	0.206E-03	0.204E-03	0.133E-03	0.318E-04	0.385E-05	0.577E-06	0.767E-07	0.815E-08		0.369E-08	0.358E-08
K = 2	0.216E-03	0.213E-03	0.138E-03	0.322E-04	0.380E-05	0.574E-06	0.765E-07	0.815E-08		0.371E-08	0.359E-08
K = 1	0.222E-03	0.218E-03	0.140E-03	0.317E-04	0.366E-05	0.566E-06	0.760E-07	0.812E-08		0.371E-08	0.360E-08

CROSS-WIND DIRECTION: CELL CONCENTRATIONS

Figure D-29. SAMPLE OUTPUT FORMAT OF RAPT

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